ASSESSING THE IMPACT OF FLEXIBLE RAMP CAPABILITY PRODUCTS IN THE MIDCONTINENT ISO

by

Adam Cornelius

Dr. Dalia Patino Echeverri, Adviser

May 2014

Masters project submitted in partial fulfillment of the

requirements for the Master of Environmental Management degree in

the Nicholas School of the Environment of

Duke University

2014

Abstract

In electric power systems, balancing authorities adjust the output of dispatchable coal and natural gas generators in response to changes in net load (electricity demand minus variable generation such as wind). As penetration of renewable energy increases, so do the variability and uncertainty surrounding net load, making balancing more difficult. The flexibility of the system to ramp power output up and down (i.e. ramping capability) may be insufficient to accommodate large changes in net load, potentially leading to scarcity events and threatening system security. The Midcontinent Independent System Operator (MISO) has proposed ancillary service products called up-ramp capability (URC) and down-ramp capability (DRC) intended to increase system flexibility.

The purpose of this study is to explore the economic, environmental, and reliability impacts of MISO's proposed ramp capability products. Two versions of the unit commitment and economic dispatch processes used by MISO to optimally schedule generators were modeled: (1) a baseline model representing current MISO practices, and (2) a ramp capability model that includes the proposed products. These models were applied to a small power system representative of MISO's mix of generators under low and high wind penetration levels.

In this model the DRC product had no impact, indicating that the representative power system was more flexible in the downward direction than MISO's actual system, perhaps due to model simplifications or inaccurate assumptions. The URC product, however, did benefit the system. Results show a reduction in the frequency of energy and operating reserve shortages when compared to the baseline model, particularly with high wind penetration, thereby indicating improved reliability. While there was a small price increase in non-shortage intervals due to procurement of URC, this was outweighed by the avoidance of high penalty prices incurred in shortage intervals; the overall average market clearing price was significantly reduced. The URC product also caused a small amount of fuel switching from coal to the more flexible natural gas, slightly reducing the system's CO_2 emissions. However, the more pronounced environmental benefit was the URC product's ability to help the system absorb increased wind penetration while avoiding most of the corresponding increase in reliability problems.

Acknowledgements

I would like express my deep gratitude to my research advisor, Dr. Dalia Patino Echeverri for her immense support and guidance in every stage of the process, from concept development to completion. I would also like to thank Ali Daraeepour for helping me to better understand electric power systems through many late-night discussions. Thank you also to Kyra Moore Holt for her assistance in developing the representative power system and to Rubenka Bandyopadhya for her help in troubleshooting CPLEX and OPL. This Master's Project would not have been possible without each of their generous contributions of time and effort.

Contact

For more information, please contact adam.cornelius@gmail.com

Contents

1. Introduction

In electric power systems, supply (i.e., generation) and demand (i.e., load) must be essentially equal at all times. Balancing Authorities are tasked with maintaining this balance in a particular region through the adequate scheduling of power generation plants and imports and exports of electricity. In regions of the United States where there has been restructuring of the electricity industry to enable wholesale markets, Independent System Operators (ISOs) administer the markets and act as the Balancing Authorities. ISOs, as their name suggests, are independent of both electricity generators and load-serving utilities. Their primary objective is to deliver electricity to meet demand at the lowest cost, while maintaining system stability [1]. In order to do so, ISOs run computer programs executing unit commitment (UC) and economic dispatch (ED) algorithms to schedule power plants' operation for every time interval. In essence, generators offer to supply a specified quantity of electricity at a particular price, along with various operating parameters. These offers are run through an optimization model to find the least-cost combination of generation that meets the forecasted load and all system constraints. In a competitive market, generators are expected to offer electricity at their marginal costs, and all generators that are called to operate are paid the marginal cost of the last unit of generation necessary to meet demand, called the market clearing price (MCP) [2]. Typically ISOs run several versions of the UC and ED models, including a day-ahead model that considers hourly intervals, and real-time dispatch (RTD), which works in 5-minute intervals.

The corollary to the requirement that supply and demand be in balance at all times is that changes in load must be met by changes in generation in near real-time. The uncertainty of electricity demand and of the availability of transmission lines and power generation units makes necessary the provision of a number of ancillary services to guarantee system reliability. Two of those services are frequency regulation and operating reserve. Generators that provide frequency regulation are equipped with Automatic Generation Controllers (AGC) that allow them to quickly (i.e. in milliseconds to seconds) raise or lower their real power generation levels in response to small changes in system frequency resulting from temporary imbalances between electrical load and generation. Operating reserve is generation capacity that is not scheduled to produce energy, but can be deployed as needed to cover imbalances due to sudden, unexpected outages of transmission lines or scheduled generation resources. Much like the energy market, generators supply offers for four separate ancillary services products: regulation up (ability to increase generation), regulation down (ability to decrease generation), spinning reserve (from units that are running, but not fully dispatched) and non-spinning reserve (from units which are available but not running). The ISO purchases the combination of energy and ancillary services that minimizes overall system cost [3].

1.1 Ramping Needs in a Power System

Because electrical load varies with time, generation must be continuously adjusted. While frequency regulation is designed to respond to load changes within a dispatch interval, it is necessary that other generators within the system ramp up and ramp down their power output as needed to handle changes between intervals as well as to replace regulation as quickly as possible to free it for use in future intervals. The "ramping capability" of generators is information that must be submitted by operators to the ISO. Hence, as part of their offers, generators submit ramp rates (maximum rate of real power output change, measured in MW/minute), startup time, and minimum and maximum generation. This information constitutes additional constraints in the UC and ED optimization problems that ISOs run to minimize system's costs while meeting demand and reliability standards. For example, one such constraint is that the energy that a generator supplies in some interval, *t*, must be less than or equal to the energy supplied in the previous interval, *t-1*, plus its maximum ramp rate times the length of the interval. Because current real-time UC and ED algorithms do not look ahead to consider energy demand levels in future intervals, there are times when there is insufficient ramping capability in the system. To the extent that this is forecasted, system operators can make out-of-market adjustments to ensure future need is met by requiring some generators to increase or decrease their power output deviating from the optimal amount suggested by the UC and ED algorithms. While these adjustments are necessary from a reliability standpoint, this practice tends to be uneconomic and inconvenient. Generators that are manually dispatched by the system operator in response to a ramping need, rather than by the optimization software, are not eligible to set the MCP. However, they are eligible to receive a revenue sufficiency guarantee (RSG) payment equal to the difference between the generator's offer price and the MCP to ensure they are able to fully recover their costs [4]. The frequency of out-of-market adjustments increases when load changes unexpectedly and there is scarce availability of generation to meet it. In these cases, ISOs activate a process of "scarcity pricing" which sets the market clearing prices at levels commensurate with the Value of Lost Load (VOLL) and causes significant price spikes. Beyond the increased electricity prices, this process of addressing ramping requirements out of the market hides the magnitude and severity of the problem and does not contribute to its prevention as it does not provide clear price signals to market participants to increase ramping capability [5].

1.2 Increased ramping needs in systems with high penetration of variable generation

Ramping needs are caused by other factors beyond sudden changes in electrical load. There are at least three other causes of increases in the amount of ramping capability required in a system: changes in variable energy resources (VERs) such as wind and solar power, changes in imports and exports, and

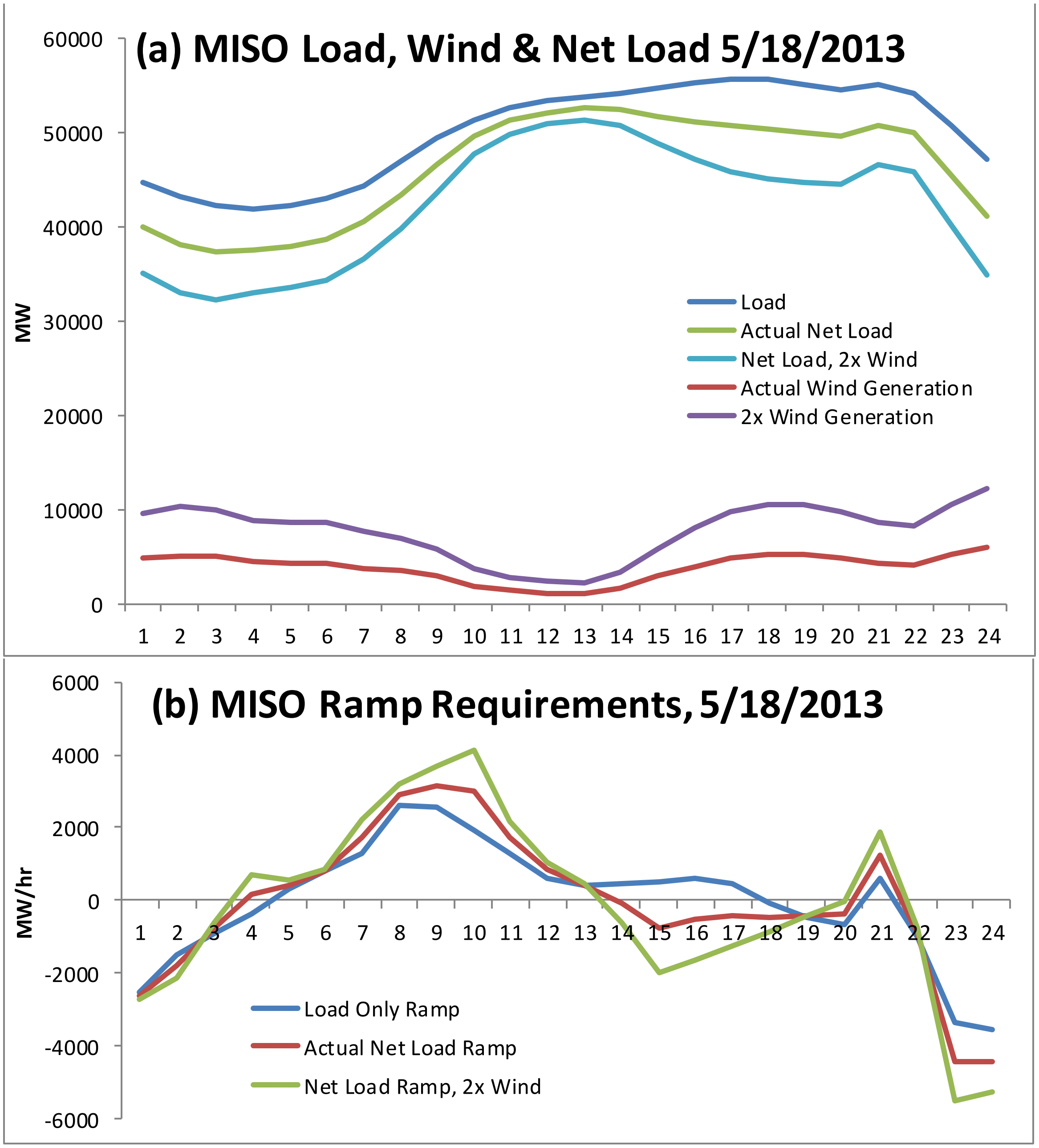

Figure 1 – Impact of wind generation on ramping needs in MISO. Part (a) shows hourly load, wind and net load May 18, 2013. In addition to actual wind levels, a scenario with twice as much wind generation is shown. Although not always the case, on this particular day wind tended to ramp in the opposite direction as load, increasing the need for ramping capability. Part (b) shows the ramping need within each hour of load, net load, and net load with twice as much wind generation. Ramp requirements increase as wind is added to the system.

deviations from instructed levels of generation by generating units. Each of these are beyond the control of the system operator, but must be met by resources that are within the operator's control. Therefore, when discussing ramping needs, it makes more sense to refer to net load and dispatchable generation. For the purposes of this paper, we ignore imports, exports and generator deviations and define net load as the difference between the system's load and non-dispatchable (i.e. VER) resources as follows:

$$Net\ Load = System\ Load - Variable\ generation \tag{1}$$

Dispatchable generation consists of all generating units whose output the system operator can control, typically thermal plants such as coal, natural gas, and nuclear. The change in net load between time intervals is the ramp need. Net load tends to have steeper slopes and greater uncertainty than load alone. As penetration of renewables increases, the issue will only be exacerbated further [5]. Figure 1 shows the relationship between load, wind generation, and net load in the Midcontinent ISO (MISO) system on May 18, 2013. As wind penetration increases, the ramping need that must be met with other generators increases in both the up and down directions.

1.3 MISO's proposal to address ramping needs

In the U.S. two ISOs, MISO [5] and the California ISO (CAISO) [6] have both proposed adding additional ancillary service products for flexible ramp capability to their markets. Their proposals are quite similar, but have slightly different formulations; this Master's project focuses on MISO's version.

MISO's proposal is to modify their UC and ED algorithms by directly accounting for the economic value of provisioning an adequate level of ramping capability as represented by a demand curve of ramping. In the context of these modifications, two new "products" arise: up-ramp capability (URC) and down-ramp capability (DRC). These products are symmetrical in their derivations, but will likely have very different prices and quantities required for a given interval. By procuring the ramp capability products the ISO intends to address both forecasted variability in net load as well as unexpected ramp needs (when load or generation deviate from their forecasts). The range of uncertainty is calculated using historical deviations from forecasts over similar intervals to identify a set number of standard deviations to cover a desired percentage of cases. For example, assuming normal distribution of forecast errors, 95.4% of the deviations are within two standard deviations of the forecast, while 99.8%

of all cases are within 3 standard deviations of the forecasts. The targeted amount of up- and down-ramp capability constraints can be generally formulated as:

$$UpRampCapability_t = \max\{(ExpectedNetLoad_{t+n} - NetLoad_t) + Uncertainty_{up_{t+n}}, 0\} \quad (2)$$

$$DownRampCapability_t = \max\{(ExpectedNetLoad_t - NetLoad_{t+n}) + Uncertainty_{down_{t+n}}, 0\} \quad (3)$$

It is important to note that ramp capability may or may not be deployed. It is simply available for the real-time dispatch to use if needed. Depending on system conditions, ramp capacity from interval *t* may be deployed as energy in interval *t+1*, may continue to be used as ramp capacity, or neither. The new dispatch for interval *t+1* simply uses available resources as economically as possible without considering previously cleared ramp capability.

Ramping capability will be simultaneously co-optimized with energy and ancillary products. Under MISO's proposal, generators will not separately offer ramp capability, nor can they opt out of offering ramp capacity. By submitting an offer to provide energy, they are essentially submitting an offer to provide whatever combination of energy and ramping capacity the dispatch model finds most cost-effective to the system (and indeed, MISO and all other system operators routinely require plants with ramping capacity to ramp up and down as it is). Generators selected to provide ramp capability will be paid based on their opportunity cost of doing so. This is different from other ancillary services (for which generators do submit offers) because unlike reserve and regulation, there are no additional requirements for providing ramping capacity.

URC and DRC are added as constraints to the model, which in any given interval will either add to the total system cost or be cost neutral. In the case of URC, if the dispatch must be altered so that a lower cost but faster ramping unit reserves some energy to meet the ramping capability, the missing energy must be replaced by a higher cost unit. The difference in price between the two generators' energy offers is the opportunity cost of procuring ramp capability and is the shadow price of the ramp capability constraint. The shadow price sets the market price for URC and generators providing URC are paid that amount to compensate them for their reduced energy award. Similarly, if a high-cost flexible unit would otherwise be operating at its minimum level but its energy level must be increased to meet the DRC constraint, it will be replacing a lower-cost unit. Again, the increased system cost is the difference in energy offers between the two generators. In this case, the generator providing DRC would be providing energy above the energy market price and the DRC payment compensates for this. In many intervals it is likely that sufficient ramping capacity is available in the system without the ramp capability constraints. In these intervals, the URC and DRC constraints are non-binding. There is no additional system cost to procure ramp capability, thus URC and DRC price is set to $0.

At times there may be insufficient power generation capacity that can be economically dispatched to meet both current energy and ramping for future needs. When this occurs, using generation for current energy should take clear priority. Demand curves for both up- and down-ramp capability are defined, which indicate the value of the ramp capability to the system and set an effective cap on the amount to be procured. MISO's proposal indicates that a single segment (i.e. flat) demand curve will be used whose precise value will be determined using a historical statistical analysis. The expected range of $5-$20 is much lower than that of operating reserve and regulation scarcity pricing, indicating that at times of scarcity, ramp capacity will be the lowest priority for generation resources [5].

Figure 2 illustrates the five possible scenarios that could occur in any given interval depending on ramping capability required, baseline levels of ramping capability and the economics of available power generators. In this example, the demand price is set at $10/MW for all intervals. In this particular interval for scenarios 2 – 5, historical analysis has indicated that the system should procure 100 MW of URC.

1. For a particular interval, historical analysis could determine that there is a very low likelihood of a need for any ramp capability and set the target amount to 0 MW.
2. If the system without the ramping constraint would have provided 120 MW anyway, the URC constraint is non-binding and the price is set at $0/MW.
3. If the system wouldn't naturally provide sufficient URC, but the cost of doing so is relatively low, the full 100 MW will be procured and the price will be set below the demand curve value, in this case $6/MW.
4. If the opportunity cost of providing ramp capability is high, the price will be capped at $10/MW which will limit the amount procured, in this case to 60 MW, leaving a shortage of URC.
5. If providing any amount of ramping capability is higher than the price cap, none will be procured.

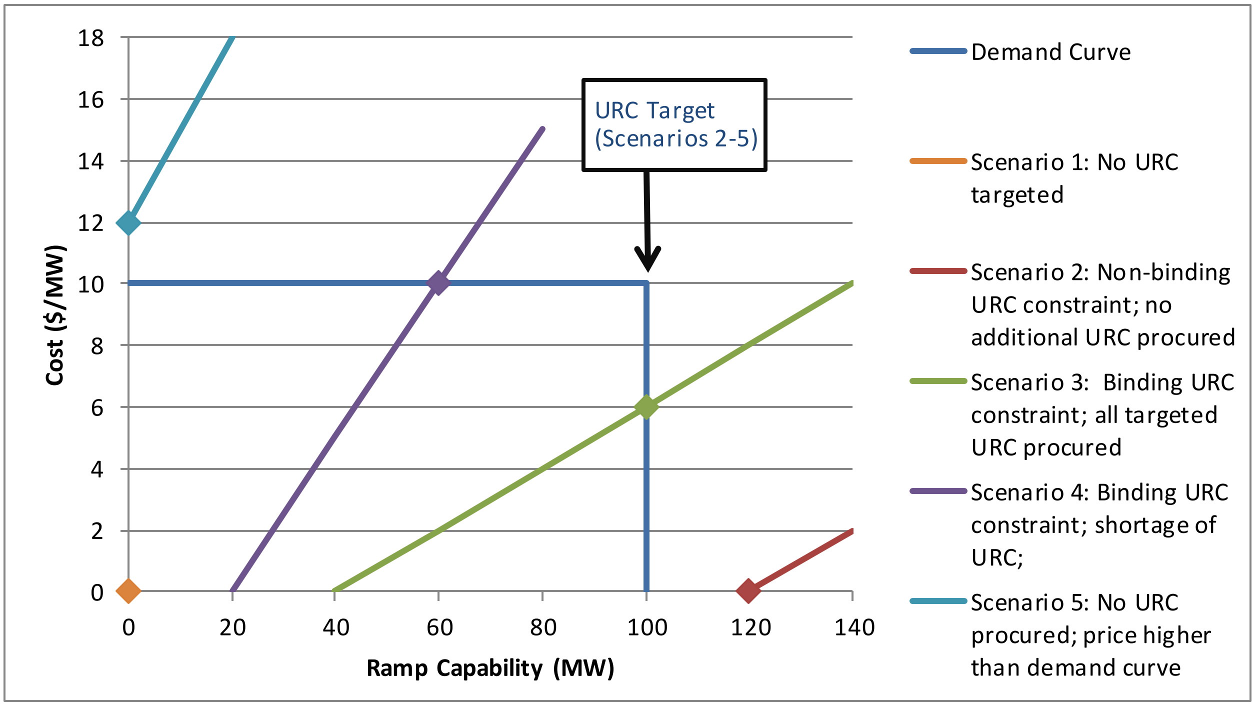

Figure 2: Demonstration of the five possible scenarios given a $10/MW URC demand curve price. The upward-sloping lines represent URC supply curves and the diamond markers indicate the market clearing quantity and price in each scenario. *Scenario 1*: Historical analysis determines no URC is needed. *Scenario 2*: Historical analysis targets 100 MW of URC. Existing generators provide 120 MW, so no additional URC is procured; the price is $0/MW. *Scenario 3*: Historical analysis targets 100 MW of URC. There is insufficient ramp capability in the system, so the ramp capability constraint is binding. All 120 MW are able to be procured for less than the $10/MW demand curve price cap. *Scenario 4:* Historical analysis targets 100 MW of URC. There is insufficient ramp capability in the system, so the ramp capability constraint is binding. Only some ramp capability is able to be procured below the $10/MW demand curve price cap, so there is a shortage of URC. *Scenario 5*: Historical analysis targets 100 MW of URC. However, the cost to provide any URC is greater than the $10/MW price cap and therefore none is procured.

MISO generally allocates costs based either on which participants benefit from a product or on which participants cause the costs to occur. Benefit-based costs would be allocated to load and exports (which is how operating reserve is currently allocated). Cause-based costs would be allocated to all four sources of variability (load, variable generation, net imports, and traditional generation). This would entail a very complex rate design; furthermore, most of the need for URC and DRC (both forecasted variability and uncertainty) is currently due to load and changes in net imports. Thus, even under cause-based allocation, a very small percentage of costs would be assigned to generation, and this small difference is not worth the complexity required. Therefore, MISO currently plans to use benefit-based costs [5].

While electricity costs will be slightly higher under normal conditions due to the need to procure extra generation. MISO expects that the URC and DRC products will provide a number of benefits to the system. First and foremost is a reduction in the magnitude and frequency of short-term scarcity conditions which cause energy market price spikes. There should be less need to dispatch high cost resources, particularly uneconomic CT generators which currently are used to provide ramping in short-term dispatch. There should be a reduced need for operators to provide manual interventions to the dispatch, which in turn will increase transparency and consistency. The supply of ramp capability will be transparently priced, which may increase the incentives for generators to invest in faster-ramping generation. Finally, reliability should be increased by reducing the frequency of reserve shortages. MISO estimates the net savings of offering this product to be in the range of $3.8-5.4 million/year under current conditions [5].

1.4 Previous studies of the effects of introducing ramping products

Navid and Rosenwald [7] provide a basic formulation for ramp capability in a real-time economic dispatch model. Several small scale examples with five or fewer generators are provided demonstrating the benefits under both single-interval and multiple interval optimizations, as well as an application in which generators can make ramp capability offers. In a later white paper outlining the specifics of MISO's proposed ramp capability product, Navid and Rosenwald [5] provide significantly more detail, as well as additional five-generator examples demonstrating how the ramp capability products would be introduced in the day-ahead unit commitment model and its impacts on billing. Additionally, 4 sample days with various net load and ramping profiles were selected and dispatched based on actual MISO data both with and without the ramp capability product for comparison. In a similar white paper for CAISO, Xu and Tretheway [6] present CAISO's proposed model, a method for deriving a stepped demand curve, and several small illustrative examples. Finally, Wang and Hobbs [8] compare costs and benefits of a deterministic dispatch model with the ramp product both to the standard dispatch model and to the stochastic ideal. In general the literature thus far indicates that the proposed ramp capability products improve system reliability when compared to existing ISO practices. Small increases in MCPs are found in some intervals in order to procure the ramp capability, but overall system costs are lowered due to a reduction in scarcity pricing and/or uplift payments. Wang and Hobbs concur but note the importance of careful selection of market elements in order to maximize system efficiency.

1.5 Objectives of this Master's Project.

The purpose of this work is to further explore the economic, environmental, and reliability costs and benefits of MISO's proposed ramp capability products. To do so, we modeled both the day-ahead unit commitment and real-time economic dispatch processes with and without the proposed products. We applied the models to a small power system representative of MISO's mix of generators using three monthly net load patterns selected from summer, winter, and shoulder (spring/fall) seasons under both low and high wind penetration levels. This is both a larger test system and a much longer simulation run than in examples in previous studies. In particular, we consider to what extent the addition of the ramp capability products reduces scarcity events and how the products impact energy prices, the generation fuel mix, and CO_2 emissions.

2. Methods

Our general method to assess the benefits of ramping products consisted of reproducing the optimization models used by electric power system operators to schedule energy and operating reserve at the lowest cost, and applying them to a scale representation of a system to perform parametric analysis on important variables. Hence, we developed a market clearing model that is in fact composed of two sub-models: unit commitment (UC) and economic dispatch (ED), where electrical generators are represented in terms of their marginal generation costs, startup costs, fixed or no-load costs, maximum up- and down-ramping rates, maximum and minimum generation levels, and minimum up and down times. The UC model is a mixed-integer linear program (MILP) that takes as inputs generators' physical constraints and cost parameters as well as system requirements and conditions such as load and wind generation levels and required reserve margins to produce a schedule that commits resources at the lowest cost (a committed resource is one that is scheduled to be on and producing electricity for the grid). The integer decision variables in this problem are associated with the commitment (i.e. on/off) status of generating units and the corresponding costs. ED is a linear program (LP) that is similar to UC, but has some key differences. Within this program, the commitment status of a generation unit is no longer a decision variable, and instead is taken as given by the solution of the previously run unit commitment model. Outputs of economic dispatch include market clearing prices and energy and reserve levels for each generator. Because of the long startup time of many generators as well as the unpredictable nature of net load, system operators run the models on multiple time scales ranging in length from several days to five minutes. In ISOs, the two most prominent model runs correspond with the day-ahead and real-time markets.

2.1 Simulation overview

To simulate MISO market operations, we developed three baseline models: day-ahead unit commitment (B-DAUC), day-ahead economic dispatch (B-DAED), and real-time economic dispatch (B-RTED). The two day-ahead models use day-ahead forecasts of load and wind generation to produce optimal hourly commitment, generation, and reserve schedules and market prices for a 24-hour period. A single iteration of the B-DAUC/B-DAED model optimizes over the full 24-hour period. The B-RTED model takes as inputs the commitment schedule from the day-ahead market and actual load and wind power levels, and produces the least-cost generation and reserve schedules and market prices for a single 10-minute interval (without considering future forecasts). This is consistent with current MISO practices, which do not consider any "look-ahead" in the RTED process, although doing so is currently under consideration [9]. A full one-day simulation consists of one iteration each of the B-DAUC and B-DAED models and 144 (i.e. 6 iterations/hour * 24hours) iterations of the B-RTED model.

We developed a second set of DAUC, DAED, and RTED models that include MISO's proposed ramp capability products (RC-DAUC, RC-DAED, RC-RTED), but otherwise operate identically to the baseline models. We ran daily simulations using the same inputs on both the baseline and ramp capability models for three one-month intervals: January, June and April, representing the three seasonal load profiles and compare economic reliability and economic outcomes. The entire process was performed for both low and high wind penetration levels of 7% and 13% by installed nameplate capacity.

2.2 Baseline Models

2.2.1 Baseline Model Notation

Indices

u: Index for dispatchable unit, $u \in 1..U$

t: Index for time interval, $t \in 0..T$

n: Intermediate time interval index used for minimum up and downtime requirements, $n \in t..T$

System Requirement Parameters

T: Number of intervals in time horizon

U: Number of dispatchable generators in the system

IntLength: Length of each time interval [minutes]

$FDemand_t$: Forecasted system demand in interval t [MW]

$ActDemand_t$: Actual system demand in interval *t* [MW]

$VForecast_t$: Forecasted wind power in interval *t* [MW]

$VAvailable_t$: Actual available wind power in interval *t* [MW]

$SpinReq_t$: Quantity of spinning reserve required in interval *t* [MW]

ResResponseTime: Time by which reserve provided by generator *u* must be deployable [minutes]

System Penalty Parameters

OverGenPen: System-wide over generation penalty [$/MWh]

UnderGenPen: System-wide under generation penalty [$/MWh]

SRScarcityPen: System-wide spinning reserve shortage penalty [$/MWh]

Generator Cost Parameters

MC_u: Marginal Cost of operating dispatchable unit *u* [$/MWh]

SRC_u: Cost of spinning reserve provided by unit *u* [$/MWh]

NLC_u: No load cost (fixed operation cost) of operating unit *u* [$/interval]

$StartC_u$: Cost of starting unit u [$]

Generator Operating Parameters

$Commit_{u,t}$: Commitment status of unit *u* in interval *t* (only a parameter in economic dispatch models) [binary]

$MaxGen_u$: Maximum generation of unit *u* [MW]

$MinGen_u$: Minimum generation of unit *u* [MW]

$PosRampRate_u$: Maximum ramp-up rate of generator *u* [MW/minute]

$NegRampRate_u$: Maximum ramp-down rate of generator *u* [MW/minute]

$MinUT_u$: Minimum uptime of unit *u* [intervals]

$MinDT_u$: Minimum downtime of unit *u* [intervals]

$InitMinUp_u$: Number of intervals generator *u* must be up at the start of the optimization period due to its initial uptime [intervals]

$InitMinDown_u$: Number of intervals generator *u* must be down at the start of the optimization period due to its initial downtime [intervals]

$Commit0_u$: Commitment status of unit *u* at end of previous time horizon [binary]

$Gen0_u$: Generation level of unit *u* at end of previous time horizon [MW]

$SR0_u$: Spinning reserve provided by unit *u* at end of previous time horizon [MW]

$FutureSD_u$: Number of intervals beyond the end of the RTED time horizon that unit *u* will shut down [intervals]

Decision Variables

$Gen_{u,t}$: Average power generation of unit *u* in interval *t* [MW]

$SR_{u,t}$: Spinning reserve provided by unit *u* in interval *t* [MW]

$Commit_{u,t}$: Commitment status of unit *u* in interval *t* (only a decision variable in unit commitment models) [binary]

$StartCost_{u,t}$: Startup cost of unit *u* in interval *t* [$]

$OverGen_t$: Surplus of generation over demand in interval *t* [MW]

$UnderGen_t$: Shortage of generation below demand in interval *t* [MW]

$UnmetSR_t$: Shortage of spinning reserve below requirement in interval *t* [MW]

$VSchedule_t$: Quantity of variable generation scheduled in interval *t* [MW]

2.2.2 Baseline Day-Ahead Unit Commitment (B-DAUC) Model

The B-DAUC model is responsible for committing generators to meet forecasted net load at the lowest cost. We formulate it as an MILP as follows:

$$Min \sum_{t=1}^{T}\left(\sum_{u=1}^{U}\left(Gen_{u,t} * MC_u + SR_{u,t} * SRC_u + Commit_{u,t} * NLC_u + StartCost_{u,t}\right) + OverGen_t * OverGenPen + UnderGen_t * UnderGenPen + UnmetSR_t * SRScarcityPen\right) \tag{4}$$

Such that:

$$Commit_{u,0} = Commit0_u \quad \forall\, u \tag{5}$$

$$Gen_{u,0} = Gen0_u \quad \forall\, u \tag{6}$$

$$SR_{u,0} = SR0_u \quad \forall\, u \tag{7}$$

$$\sum_{u=1}^{U} Gen_{u,t} + VSchedule_t + UnderGen_t - OverGen_t = FDemand_t \quad \forall\, t \in 1..T \tag{8}$$

$$\sum_{u=1}^{U} SR_{u,t} + UnmetSR_t \geq SpinReq_t \quad \forall\, t \in 1..T \tag{9}$$

$$VSchedule_t \leq VForecast_t \;\; \forall\, t \in 1..T \tag{10}$$

$$StartCost_{u,t} \geq StartC_u * \left(Commit_{u,t} - Commit_{u,t-1}\right) \quad \forall\, u, \forall\, t \in 1..T \tag{11}$$

$$Gen_{u,t} + SR_{u,t} \leq MaxGen_u * Commit_{u,t} \;\; \forall\, u, \forall\, t \in 1..T \tag{12}$$

$$Gen_{u,t} \geq MinGen_u * Commit_{u,t} \;\; \forall\, u, \forall\, t \in 1..T \tag{13}$$

$$Gen_{u,t} - Gen_{u,t-1} \leq IntLength * PosRampRate_u \;\; \forall\, u, \forall\, t \in 1..T \tag{14}$$

$$Gen_{u,t-1} + SRes_{u,t-1} - Gen_{u,t} \leq IntLength * NegRampRate_u \;\; \forall\, u, \forall\, t \in 1..T \tag{15}$$

$$\frac{SRes_{u,t}}{ResResponseTime} \leq PosRampRate_u \;\; \forall\, u, \forall\, t \in 1..T \tag{16}$$

$$\sum_{t=1}^{InitMinUp_u} \left(1 - Commit_{u,t}\right) = 0 \quad \forall\, u \tag{17}$$

$$\sum_{n=t}^{t+MinUT_u-1} Commit_{u,n} \geq MinUT_u * \left(Commit_{u,t} - Commit_{u,t-1}\right) \;\forall\, u, \forall\, t \in \{InitMinUp_u + 1, T - MinUT_u + 1\} \tag{18}$$

$$\sum_{n=t}^{T} \left(Commit_{u,n} - \left(Commit_{u,t} - Commit_{u,t-1}\right)\right) \geq 0 \quad \forall\, u, \forall t \in \{T - MinUT_u + 2, T\} \tag{19}$$

$$\sum_{t=1}^{InitMinDown_u} Commit_{u,t} = 0 \quad \forall\, u \tag{20}$$

$$\sum_{n=t}^{t+MinDT_u-1} \left(1 - Commit_{u,n}\right) \geq MinDT_u * \left(Commit_{u,t-1} - Commit_{u,t}\right) \;\forall\, u, \forall\, t \in \{InitMinDown_u + 1, T - MinDT_u + 1\} \tag{21}$$

$$\sum_{n=t}^{T}\Big((1 - Commit_{u,n}) - \big(Commit_{u,t-1} - Commit_{u,t}\big)\Big) \geq 0 \quad \forall\, u, \forall t \in \{T - MinDT_u + 2, T\} \tag{22}$$

$$Gen_{u,t}, SR_{u,t}, StartCost_{u,t}, OverGen_t, UnderGen_t, UnmetSR_t, VSchedule_t \geq 0\ \forall u, t \tag{23}$$

The objective function (4) minimizes the total cost of meeting the forecasted load over all intervals in the time horizon subject to the constraints (5)-(23).

Constraints (5)-(7) initialize interval 0 of certain decision variables to the ending status of the previous time horizon.

Constraints (8)-(10) ensure that load and spinning reserve requirements are met in each interval and that scheduled wind generation is not greater than the forecast. A series of penalties and relative prices sets priorities in the event that energy and/or spinning reserve requirements cannot be met:

- Constraint (10) allows wind generation to be curtailed. However because we assume that wind generation has no marginal cost it will be prioritized over dispatchable generators.
- Because *OverGenPen* is positive, over generation will only occur if all wind has been curtailed.
- *SRScarcityPen* is much higher than marginal cost of the most expensive generator, but much lower than *UnderGenPen*, ensuring that energy requirements are prioritized over reserve requirements in a shortage event.

Constraints (12)-(13) ensure that if a generator's status is on, then it is operating within its upper and lower generation limits, and that being called to provide any spinning reserve would not violate the upper generation limit. Constraints (14)-(16) restrict changes in generation and spinning reserve based on the generator's maximum up- and down-ramp rates.

Many UC formulations include binary variables for startup and shutdown intervals in addition to the binary commitment variables. However Carrión and Arroyo [10] demonstrated a formulation that we use here which only utilizes the commitment variables, thereby reducing the number of binary variables by 2/3. Because computational efficiency of MILPs depends heavily on the number of binaries, their formulation offers significant savings in computation time, although the corresponding minimum uptime

(17) – (19) and downtime (20) – (22) constraints are somewhat more complicated. An additional constraint (11) and decision variable, $StartCost_u$, is necessary in this formulation to ensure that startup cost is not negative when the unit is shutting down. Constraint (23) ensures that the non-binary decision variables are not negative.

2.2.3 Baseline Day Ahead Economic Dispatch model (B-DAED)

Given the commitment output from B-DAUC, B-DAED runs over the same time intervals and uses the same load and VER forecasts and produces the optimal dispatch levels for each generator. B-DAED is an LP, so unlike B-DAUC, it is able to generate shadow prices for both energy and spinning reserve, which are used as the market clearing prices. The formulation is as follows:

$$Min \sum_{t=1}^{T}\left(\sum_{u=1}^{U}\left(Gen_{u,t} * MC_u + SR_{u,t} * SRC_u\right) + OverGen_t * OverGenPen + UnderGen_t * UnderGenPen + UnmetSR_t * SRScarcityPen\right) \tag{24}$$

such that

$$Gen_{u,0} = Gen0_u \quad \forall\, u \tag{25}$$

$$SR_{u,0} = SR0_u \quad \forall\, u \tag{26}$$

$$\sum_{u=1}^{U} Gen_{u,t} + VSchedule_t + UnderGen_t - OverGen_t = FDemand_t \quad \forall\, t \in 1..T \tag{27}$$

$$\sum_{u=1}^{U} SR_{u,t} + UnmetSR_t \geq SpinReq_t \quad \forall\, t \in 1..T \tag{28}$$

$$VSchedule_t \leq VForecast_t \quad \forall\, t \in 1..T \tag{29}$$

$$Gen_{u,t} + SR_{u,t} \leq MaxGen_u * Commit_{u,t} \quad \forall\, u, \forall\, t \in 1..T \tag{30}$$

$$Gen_{u,t} \geq MinGen_u * Commit_{u,t} \quad \forall\, u, \forall\, t \in 1..T \tag{31}$$

$$Gen_{u,t} - Gen_{u,t-1} \leq IntLength * PosRampRate_u \quad \forall\, u, \forall\, t \in 1..T \tag{32}$$

$$Gen_{u,t-1} + SRes_{u,t-1} - Gen_{u,t} \leq IntLength * NegRampRate_u \quad \forall\, u, \forall\, t \in 1..T \tag{33}$$

$$\frac{SRes_{u,t}}{ResResponseTime} \leq PosRampRate_u \quad \forall\, u, \forall\, t \in 1..T \tag{34}$$

$$Gen_{u,t}, SR_{u,t}, OverGen_t, UnderGen_t, UnmetSR_t, VSchedule_t \geq 0 \;\forall u, \forall\, t \in 1..T \tag{35}$$

The components of B-DAUC's objective function that rely on the commitment decision variable have been removed here. There are no new or modified constraints, although several have been removed. The shadow prices of (27) and (28) provide the day-ahead market clearing prices for energy and spinning reserve respectively.

2.2.4 Baseline Real-Time Economic Dispatch (B-RTED) Model

The B-RTED model takes the commitment schedule output from the B-DAUC model and optimizes in real-time over a single shorter interval using actual load and VER availability. The formulation is similar to the B-DAED model in section 2.2.3 with three modified constraints reflecting that this model considers actual load and variable generation available rather than forecasts, as well as one additional constraint.

Constraint (27) is replaced with:

$$\sum_{u=1}^{U} Gen_{u,t} + VAvailable_t + UnderGen_t - OverGen_t = ActDemand_t \quad \forall\, t \in 1..T \tag{36}$$

Constraint (29) is replaced with:

$$VSchedule_t \leq VAvailable_t \;\; \forall\, t \in 1..T \tag{37}$$

Constraint (33) is replaced with

$$Gen_{u,t-1} - Gen_{u,t} \leq IntLength * NegRampRate_u \;\; \forall\, u, \forall\, t \in 1..T \tag{38}$$

New Constraint:

$$Gen_{u,t} + SRes_{u,t} \leq (FutureSD_u + T - t) * IntLength * NegRampRate_u \;\; \forall\, u, \forall\, t \in 1..T \tag{39}$$

Constraint (33) in B-DAED restricts the down-ramp capability of a generator based on both energy and spinning reserve in interval *t*-1. This is necessary because in the day-ahead models all intervals are considered simultaneously. However, in the real-time model, when only one interval is considered at a time, we know whether or not the spinning reserve was deployed in interval t-1; if it was, it would be included in generation from that interval and therefore we do not need to include it in constraint (38).

Constraint (39) is in place to manage the change in time-resolution between the day-ahead and real-time interval lengths. Consider the following example demonstrating the need. The day-ahead interval length is 60 minutes and the real-time interval length is 10 minutes. Unit A has a ramp rate of 5 MW per minute, minimum generation of 20 MW and maximum generation of 200 MW. In the day-ahead model run, it is scheduled to provide 100 MW in the hour ending at 19:00 and shutdown in the following hour. With 60 minutes to shut down, the unit can do so within its ramp rate parameter. In the B-RTED model, the generator is scheduled to be on in the interval ending at 19:00 and off in the interval ending at 19:10. However, because the B-RTED model only considers one interval at a time, the 19:00 model run is not "aware" of the impending shutdown and may dispatch it at 100 MW. With only 10 minute interval lengths, and a 5 MW/minute ramp rate, the unit will be unable to ramp down fast enough to be fully shut down by 19:10. The $FutureSD_u$ parameter contains the number of (10 minute) intervals beyond the B-RTED horizon that unit u will be shut down, so that constraint (39) limits generation accordingly.

2.3 Ramp Capability Models

We added several additional parameters and decision variables and changed the objective functions and constraints in order to implement the ramp capability product for each model.

2.3.1 Ramp Capability Notation

The ramp capability products require the following parameters and decision variables in addition to those found in section 2.2.1.

System Requirement Parameters

$RCUpDCMax_t$: The targeted amount of up-ramp capability (URC) in interval t [MW]

$RCDownDCMax_t$: The targeted amount of down-ramp capability (DRC) in interval t [MW]

RampResponseTime: Response time for ramp capability (used in day-ahead models) [minutes]

RampInts: Number of intervals for which ramp capability is considered (used in real-time model) [intervals]

System Price Parameters

RCUpDCPrice: URC Demand Curve Price [$/MWh]

RCDownDCPrice: DRC Demand Curve Price [$/MWh]

Decision Variables

$UnitRCUp_{u,t}$: URC supplied by unit *u* in interval *t* [MW]

$UnitRCDown_{u,t}$: DRC supplied by unit *u* in interval *t* [MW]

$RCUp_t$: System URC procured in interval *t* [MW]

$RCDown_t$: System DRC procured in interval *t* [MW]

2.3.2 Ramp Capability Day-Ahead Unit Commitment (RC-DAUC) Model

The RC-DAUC model is similar to the B-DAUC model found in 2.2.2 with the following changes and additions.

Objective function additional components:

$$-\sum_{t=1}^{T}\left(RCUp_{u,t} * RCUpDCPrice + RCDown_{u,t} * RCDownDCPrice\right) \tag{40}$$

Change to constraint (12)

$$Gen_{u,t} + SR_{u,t} + UnitRCUp_{u,t} \leq MaxGen_u * Commit_{u,t} \;\; \forall\, u, \forall\, t \in 1..T \tag{41}$$

Change to constraint (13)

$$Gen_{u,t} - UnitRCDown_{u,t} \geq MinGen_u * Commit_{u,t} \;\; \forall\, u, \forall\, t \in 1..T \tag{42}$$

Change to constraint (16)

$$\frac{UnitRCUp_{u,t}}{RampResponseTime} + \frac{SRes_{u,t}}{ResResponseTime} \leq PosRampRate_u \;\; \forall\, u, \forall\, t \in 1..T \tag{43}$$

Additional components to constraint (18)

$$UnitRCUp_{u,t}, UnitRCDown_{u,t}, RCUp_t, RCDown_t \geq 0 \quad \forall\, t \in 1..T \tag{44}$$

New Constraints:

$$\frac{UnitRCDown_{u,t}}{RampResponseTime} \leq NegRampRate_u \;\; \forall u, \forall\, t \in 1..T \tag{45}$$

$$RCUp_t \leq RCUpDCMax_t \;\; \forall\, t \in 1..T \tag{46}$$

$$RCDown_t \leq RCDownDCMax_t \;\; \forall\, t \in 1..T \tag{47}$$

$$\sum_{u}^{Units} UnitRCUp_{u,t} \geq RCUp_t \quad \forall\, t \in 1..T \tag{48}$$

$$\sum_{u}^{Units} UnitRCDown_{u,t} \geq RCDown_t \quad \forall\, t \in 1..T \tag{49}$$

Unlike energy and spinning reserve, we formulated ramp capability as a benefit to the system rather than a cost to be consistent with MISO's proposal; therefore the value of additional ramp capability procured is subtracted from the cost minimizing objective function (40). *RCUpDCPrice* and *RCDownDCPrice* are the demand curve values of procuring additional ramp capability. Any ramp capability whose opportunity cost is higher than these values will not be procured, as the costs will outweigh the benefits. Because this value is much lower than the penalties associated with spinning reserve and energy shortages, these other products are prioritized over ramp capability.

Constraints (41)-(43) and (45) modify the minimum and maximum generation and generator ramp rate constraints to ensure that utilization of procured ramping capability does not violate these constraints. Constraint (44) prevents the new decision variables associated with ramp capability from being negative.

$RCUpDCMax_t$ and $RCDownDCMax_t$ are the targeted quantities of ramp capability within the system and therefore act as upper bounds on $RCUp_t$ and $RCDown_t$, the actual quantities that the system procures in constraints (46)-(47). Constraints (48)-(49) ensure that the actual units within the system can provide the amount of ramp capability to be procured. In intervals where the committed units provide more ramp capability than the *DCMax* target, the system does not need to procure any additional ramp capability, so either *RCUp* or *RCDown* will be 0.

2.3.3 Ramp Capability Day Ahead Economic Dispatch (RC-DAED) Model

The RC-DAED model is similar to the B-DAED model with the following changes and additions needed to include the ramp capability products:

Objective function additional components:

$$-\sum_{t=1}^{T}\left(RCUp_{u,t} * RCUpDCPrice + RCDown_{u,t} * RCDownDCPrice\right) \quad (50)$$

Change to constraint (30) (51)

$$Gen_{u,t} + SR_{u,t} + UnitRCUp_{u,t} \leq MaxGen_u * Commit_{u,t} \;\; \forall\, u, \forall\, t \in 1..T$$

Change to constraint (31) (52)

$$Gen_{u,t} - UnitRCDown_{u,t} \geq MinGen_u * Commit_{u,t} \;\; \forall\, u, \forall\, t \in 1..T$$

Change to constraint (34)

$$\frac{UnitRCUp_{u,t}}{RampResponseTime} + \frac{SRes_{u,t}}{ResResponseTime} \leq PosRampRate_u \;\; \forall\, u, \forall\, t \in 1..T \quad (53)$$

Additional components to constraint (35) (54)

$$UnitRCUp_{u,t}, UnitRCDown_{u,t}, RCUp_t, RCDown_t \geq 0 \;\; \forall\, t \in 1..T$$

New Constraints:

$$\frac{UnitRCDown_{u,t}}{RampResponseTime} \leq NegRampRate_u \;\; \forall u, \forall\, t \in 1..T \quad (55)$$

$$RCUp_t \leq RCUpDCMax_t \;\; \forall\, t \in 1..T \quad (56)$$

$$RCDown_t \leq RCDownDCMax_t \;\; \forall\, t \in 1..T \quad (57)$$

$$\sum_{u}^{Units} UnitRCUp_{u,t} \geq RCUp_t \quad \forall\, t \in 1..T \quad (58)$$

$$\sum_{u}^{Units} UnitRCDown_{u,t} \geq RCDown_t \quad \forall\, t \in 1..T \quad (59)$$

RC-DAED operates similarly to B-DAED, with the changes to accommodate ramp capability described in section 2.3.2. The shadow prices of constraints (56) and (57) are the day-ahead market clearing prices of URC and DRC.

2.3.4 Ramp Capability Real-Time Economic Dispatch (RC-RTED) Model

RC-RTED operates similarly to RC-DAED with the following changes and additions.

Change to constraint (27):

$$\sum_{u=1}^{U} Gen_{u,t} + VSchedule_t + UnderGen_t - OverGen_t = ActDemand_t \quad \forall\, t \in 1..T \tag{60}$$

Change to constraint (29):

$$VSchedule_t \leq VAvailable_t \;\; \forall\, t \in 1..T \tag{61}$$

Change to constraint (33):

$$Gen_{u,t-1} - Gen_{u,t} \leq IntLength * NegRampRate_u \;\; \forall\, u, \forall\, t \in 1..T \tag{62}$$

Change to constraint (34):

$$\frac{UnitRCUp_{u,t}}{RampInts * Intlength} + \frac{SRes_{u,t}}{ResResponseTime} \leq PosRampRate_u \;\; \forall\, u, \forall\, t \in 1..T \tag{63}$$

Change to constraint (55):

$$\frac{UnitRCDown_{u,t}}{RampInts * Intlength} \leq NegRampRate_u \;\; \forall u, \forall\, t \in 1..T \tag{64}$$

New Constraint:

$$Gen_{u,t} + SRes_{u,t} + UnitRCUp_{u,t} \leq (FutureSD_u + T - t) * IntLength * NegRampRate_u \;\; \forall\, u, t \tag{65}$$

The changes in constraints (60)-(62) and new constraint (65) are the same changes we implemented between B-DAED and B-RTED in section 2.2.4. Constraints (63)-(64) represent slightly different purposes for the ramp capability products in the day-ahead versus the real-time models. In the day-ahead models we procure ramp capability to ensure that there is sufficient intra-interval flexibility to manage real-time variability, and therefore consider a ramp response time measured in minutes. In the real-time model, on the other hand, we procure ramp capability to manage variability and uncertainty in future intervals, and thus we consider ramping needs over some number of intervals (*RampInts*).

2.4 Representative Power System

We assessed the impact of adding ramp capability products in MISO by running the baseline and ramp capability market clearing optimization models on a 6% scale representation of the MISO power system. The following sections describe the way we designed the scale system to represent important attributes of the infrastructure, resources and demand in MISO.

2.4.1 Capacity Mix and Generator Selection

We used the US Environmental Protection Agency's Emissions & Generation Resource Integrated Database 2012 (eGRID), which contains 2009 data, to determine the percentage of generating capacity of each major fuel type (Coal, Natural Gas, Nuclear, Hydro, Wind, and Other) [11]. We chose to only utilize coal, natural gas, and wind generation. Nuclear plants typically have essentially fixed operating levels and are extremely slow-ramping, taking multiple days to start up and shut down, and therefore neither fit well within the single-day optimization of our model, nor would they be impacted by the flexible ramping products. All other fuel sources represent less than 5% of generating capacity within MISO. We created both a low and high wind scenario representing 2009 and forecasted 2015 wind penetration levels respectively. See Table 1 for capacity mixes of the full MISO system as well as the two scenarios.

2009 MISO Full and 6% Scaled Capacity Mix									
		Coal	**Natural Gas**	**Wind**	**Nuclear**	**Hydro**	**Other**	**Total**
2009 MISO Full [11]	**Capacity (MW)**	69,718	35,407	8,096	8,597	3,551	7,065	**132,434**
	% of Total	53%	27%	6%	6%	3%	5%	**--**
Low Wind Scenario	**Capacity (MW)**	4,729	2,354	526	0	0	0	**7,609**
	% of Total	62%	31%	7%	0%	0%	0%	**--**
High Wind Scenario	**Capacity (MW)**	4,729	2,354	1,060	0	0	0	**8,143**
	% of Total	58%	29%	13%	0%	0%	0%	--

Table 1 - Name plate capacity by fuel type of actual 2009 MISO system and our 6% scaled representative grid under both high and low wind penetration scenarios.

We performed two-dimensional k-means clustering analysis by name plate capacity and heat rate on coal and natural gas combined cycle generators larger than 50 MW listed within eGRID to select sample generators. The coal analysis contained 5 clusters and the natural gas analysis contained 3 clusters. The natural gas clusters included only combined cycle plants which represent 90% of the natural gas-fired generation in MISO. See Table 2 for descriptive statistics of coal generator clusters, and Table 3 for natural gas generator clusters. We then randomly selected generators from each cluster such that the capacity of selected generators within a cluster was roughly proportionate to the capacity of the whole cluster. Finally, generic sample power plants were created using 1-3 generators of the same type. This procedure ensured that the sample of generators was a good representation of the efficiency (as measured by heat rate), fuel source and technology of MISO's generation capacity.

Summary Statistics for Representative Coal Plant Generator Parameters				
		NP Capacity (MW)	Heat Rate (mmBtu/MWh)	Age as of 2009 (years)
Cluster 1	**Mean**	121	11849	47
	Median	114	11498	49
	Standard Deviation	47	2506	9
Count	**Minimum**	54	9151	19
98	**Maximum**	218	31792	60
Cluster 2	**Mean**	328	11128	38
	Median	324	10958	40
	Standard Deviation	58	899	11
Count	**Minimum**	231	9458	0
37	**Maximum**	441	14359	52
Cluster 3	**Mean**	82	6756	15
	Median	78	6496	11
	Standard Deviation	20	980	16
Count	**Minimum**	54	5663	0
8	**Maximum**	105	8397	47
Cluster 4	**Mean**	801	10267	28
	Median	815	9960	30
	Standard Deviation	76	801	9
Count	**Minimum**	698	9657	2
14	**Maximum**	923	12556	38
Cluster 5	**Mean**	569	10478	33
	Median	574	10427	34
	Standard Deviation	51	747	8
Count	**Minimum**	456	9200	1
37	**Maximum**	640	11958	51
Overall	***Mean***	*293*	*11126*	*40*
	Median	*190*	*10907*	*40*
	Standard Deviation	*230*	*2163*	*13*
Count	***Minimum***	*54*	*5663*	*0*
194	***Maximum***	*923*	*31792*	*60*

Table 2 - Summary statistics for name plate capacity, heat rate, and age as of 2009 of each of the five clusters used to select representative coal generators

Summary Statistics for Representative Natural Gas Plant Generator Parameters				
		NP Capacity (MW)	Heat Rate (mmBtu/MWh)	Age as of 2009 (years)
Cluster 1	**Mean**	83	8295	16
	Median	87	8679	14
	Standard Deviation	21	1641	14
Count	**Minimum**	54	6620	2
33	**Maximum**	137	13167	58
Cluster 2	**Mean**	183	7694	6
	Median	185	7634	6
	Standard Deviation	19	1147	4
Count	**Minimum**	147	4790	0
37	**Maximum**	213	10804	22
Cluster 3	**Mean**	269	7472	6
	Median	250	7519	6
	Standard Deviation	48	1021	4
Count	**Minimum**	230	4790	1
17	**Maximum**	410	9847	19
Overall	***Mean***	*162*	*7879*	*10*
	Median	*171*	*7634*	*7*
	Standard Deviation	*75*	*1364*	*10*
Count	***Minimum***	*54*	*4790*	*0*
87	***Maximum***	*410*	*13167*	*58*

Table 3 - Summary statistics for name plate capacity, heat rate, and age as of 2009 of each of the three clusters used to select representative natural gas generators

2.4.2 Generator Costs and Operating Parameters

Most costs and parameters were not readily available and we relied on assumptions drawn from a variety of academic and government sources. In general, we assumed MISO to be a fully competitive market in which generators are offering their marginal costs. For all operating parameters used, see Table 4. For cost parameters, see Table 5.

We took *maximum capacity* and *CO_2 emission rates* of generators directly from eGRID 2012 [11].

We took information on *minimum up time* and *minimum down time* of generators from FERC's RTO Unit Commitment Test System (FRUCTS) [12] which contains parameters and costs for a very large set of generators in the PJM system [13]. FRUCTS used PJM's default system-wide minimum up and down times for each fuel type.

FRUCTS estimated *startup costs and fixed costs* based on historic generator bid data and heat rate levels in PJM. We assumed that MISOs generators with similar heat-rates and nameplate capacities would have the same startup and fixed costs as those of generators bidding in the PJM market.

FRUCTS estimated *minimum generation* based on historic generator output levels within PJM. We again assumed that MISO generators with similar heat-rates and nameplate capacities would have similar parameters as those of generators bidding in the PJM market and thereby assign initial minimum capacity levels. However, because our RTED models do not differentiate between operational ramp rates and ramp rates at startup or shutdown we needed to adjust each generator's minimum generation value to make sure it was not higher than the plant's ramping capacity in one real-time interval. So:

$$MinGen_u = Minimum(MinGen_{u,FRUCS}, RampRate_u * RTIntLength) \tag{66}$$

We estimated *ramp rates* based on a comparative study of coal and gas power plants in the US by the International Energy Agency which states that coal plants built before 1960 have maximum ramp rates of about 0.6% of their nameplate capacity per minute, while coal plants built after 2000 and natural gas combined cycle plants could achieve 15-25 MW/minute [14]. For each of the natural gas plants as well as the single coal plant built after 2000, we randomly generated a number between 15 and 25 to serve as the generator ramp rate in MW/minute. Resulting values are reported in Table 4. All other coal plants were built between 1953 and 1978. We set their generator ramp rates to between 0.6% and 2% of name plate capacity.

We assumed that fuel costs are the only *energy marginal costs,* and estimated them using eGRID's heat rate data and a best approximation of fuel prices. Coal price in the electric power sector floated between $1.60 and $1.75 per mmBtu in 2011 and 2012 in the West North Central region and between $2.30 and $2.40 in the East North Central region, so we used $2/mmBtu [15, 16]. We used $4/mmBtu for natural gas, which was the average power plant cost over 2012-13 [17].

Spinning reserve costs are typically much lower than energy costs. We assumed spinning reserve offers to be 20% of energy marginal cost.

Plant #	Fuel	# of Generators	Min Generation (MW)	Max Generation (MW)	Min Uptime (hours)	Min Downtime (hours)	Max Ramp Rate (MW/min)	CO_2 Emission Rate (lb./MWh)
1	Coal	3	13.5	75.0	9	15	1.4	2,423
2	Coal	3	33.0	183.3	9	15	3.3	2,288
3	Coal	3	25.9	144.0	9	15	2.6	2,946
4	Coal	3	108.3	280.0	9	15	16.6	2,511
5	Coal	1	4.9	81.6	9	15	0.5	1,785
6	Coal	2	87.1	725.8	9	15	8.7	2,059
7	Coal	2	68.9	574.3	9	15	6.9	2,140
8	Natural Gas	2	43.6	130.7	2	3	17.5	789
9	Natural Gas	2	94.4	283.1	4	5	21.8	1,107
10	Natural Gas	2	132.0	396.0	3	6	19.8	858
11	Natural Gas	2	122.5	367.5	4	5	22.2	863

Table 4 - Generator operating parameters in 6% scaled representative grid. Note that most plants have multiple generators; parameters listed are per-generator, not per-plant.

Plant #	Fuel	# of Generators	Energy Cost ($/MWh)	Spinning Reserve Cost ($/MWh)	Startup Cost ($)	Fixed Cost ($/hr.)
1	Coal	3	23.08	4.62	2,987.83	574.00
2	Coal	3	21.81	4.36	6,229.04	2,200.00
3	Coal	3	28.72	5.74	14,066.30	964.00
4	Coal	3	24.48	4.90	9,761.40	696.00
5	Coal	1	16.79	3.36	15,231.40	681.00
6	Coal	2	19.63	3.93	9,254.58	1985.00
7	Coal	2	20.85	4.17	23,943.40	2000.00
8	Natural Gas	2	27.00	5.40	1,949.75	650.00
9	Natural Gas	2	37.26	7.45	6,730.83	800.00
10	Natural Gas	2	28.89	5.78	6,751.96	1100.00
11	Natural Gas	2	29.04	5.81	9,504.82	1250.00

Table 5 - Generator cost parameters in 6% scaled representative grid. Note that most plants have multiple generators; costs listed are per-generator, not per-plant.

2.4.3 Wind Generation

We developed two sets of hypothetical wind farms based on 2009 and forecasted 2015 levels using simulated data from the National Renewable Energy Laboratory's Eastern Wind Integration and Transmission Survey (EWITS) [18]. EWITS data contains day-ahead hourly forecasts and real-time 10-minute power levels. To choose the sites, and set their capacity levels, we took the steps below. See Table 6 for calculated wind farm capacity factors.

Low Wind Scenario

1. The low wind scenario is based on MISO nameplate wind capacity in 2009 as represented in eGRID 2012 of 8087 MW [11]. Four MISO states, Iowa, Minnesota, Indiana, and North Dakota had significantly more installed capacity than other MISO states.
2. We randomly chose a simulated wind farm from each of the four states from the EWITS dataset and ensured the farm was within MISO territory.
3. We determined a scale value for each simulated wind farm so that their total generation would represent 6% of 2009 levels and the proportion of generation of each farm would roughly match that of its state's.
4. We multiplied the day-ahead and real-time values by the scale factor for each site and then summed to get a single set of wind forecasts and real-time generation levels.

High Wind Scenario

1. The high wind scenario is based on projected MISO wind capacity in 2015 of 16,600 MW [19]. To achieve this capacity of 13% we assumed installation of the same wind farms included in the low-wind scenario and added an additional randomly-selected EWITS farm from Illinois, a state which by 2013 had the second-most wind in the region [20].
2. Steps 3-4 are the same as above except a new scale factor for each farm was selected such that their combined nameplate capacity totaled 6% of 2015 projected MISO wind capacity with proportions representing 2013 capacity for each state.

	Iowa	Indiana	Minnesota	North Dakota	Illinois	System Total
EWITS Wind farm number	2443	4913	1924	273	7070	**--**
EWITS Site Latitude	42.573	40.095	44.492	45.966	40.337	**--**
EWITS Site Longitude	-93.643	-86.491	-95.856	-98.964	-91.333	**--**
EWITS Site Nameplate Capacity (MW)	278	279	295	297	295	**--**
2009 State Installed Capacity (eGRID)	3,442	1,037	1,603	958	111	**8,087**
Low Wind Scenario Scale Factor	0.92	0.28	0.41	0.24	--	**--**
Low Wind Scenario Nameplate Capacity (MW)	256	78	121	71	--	**526**
2013 State Installed Capacity (AWEA) (may include non-MISO area within a state)	5,133	1,543	2,987	1,681	3,568	**16,600 (MISO projected 2015)**
High Wind Scenario Scale Factor	1.25	0.37	0.77	0.43	0.86	**--**
High Wind Scenario Nameplate Capacity (MW)	346	104	226	128	255	**1,059**

Table 6 - Actual wind nameplate capacity in MISO states in 2009 and 2013 and nameplate capacities of simulated wind farms in low and high wind scenarios. Note that the 2009 and 2013 state installed capacities sum to less than the MISO system total, as there are other states in the MISO region which contain smaller amounts of wind capacity.

2.4.4 Load

5-Minute real-time load data in MISO is collected and published by LCG Consulting, a firm that serves ISO market participants. We used their data from January, April, and July of 2010 as the real-time load for our simulations [21]. Load data was missing for approximately 0.6% of all intervals. These values were estimated using the following methods:

1. If a single data point was missing, it was replaced with the average of the intervals directly preceding and following it.
2. There were two longer time periods of missing data, one lasting for just over 7 hours, and the other for 35 minutes. In these instances, we generated the missing data using the 5-minute load changes from the previous day.

Because the wind data was only available in 10-minute intervals, this was the granularity used for our real-time model runs. We converted the load data to 10-minute intervals by taking the averages of two consecutive intervals. We then scaled each value down to 6.5% of its original. Table 7 shows minimum, maximum, and average load for each month.

10-minute Load (MW) - Summary Statistics			
	Min	**Max**	**Average**
January	3,268	5,568	4,563
April	2,799	4,548	3,762
July	3,218	6,779	5,080

Table 7 - Demand summary statistics for each month

2.4.5 Forecasts

All day-ahead models rely on hourly forecasts for both load and wind for the following day and the real-time ramp capability model uses the forecast for the next 10-minute interval. The EWITS simulated data set that we used for wind generation contains hourly day-ahead forecasts. However, the other forecasts needed to be simulated. These were randomly generated based on MISO's reported forecast error levels. MISO's mean forecast errors are all 0. Day-ahead load forecast error has a standard deviation of 1%. 5-minute load and wind forecast errors have standard deviations of 0.12% and 3%; we increased these levels to 0.2% and 4% respectively because we used 10-minute intervals [5].

For day-ahead load, we first found the hourly real-time load by averaging the loads from the six 10-minute intervals. Next we generated the day-ahead forecast error % by generating a random normal variable with mean 0 and standard deviation 0.01. The day-ahead forecast was set to the real-time value increased or decreased by a percentage equal to the randomly generated forecast error, as in (68) below:

Define:

h: Index for day-ahead time intervals, $h \in 1..24$

t: Index for real-time time intervals, $t \in 1..144$

E_h: Day-ahead load forecast error in interval h (%)

$FDemand_h$: Day-ahead forecasted load in interval h (MW)

$ActDemand_t$: Actual real-time demand in interval t (MW)

Day-ahead load forecast formulation:

$$E_h \sim N(0, 0.0001) \tag{61}$$

$$FDemand_h = (1 + E_h) * Average(ActDemand_{6*h+1}, \ldots ActDemand_{6*h+6}) \tag{68}$$

A similar procedure was followed for 10-minute wind and load forecasts.

2.4.6 Other System Parameters

See Table 8 for all system-wide parameters used in each model. Selected explanations follow.

Spinning Reserve Percentage and Reserve Response Time: MISO currently schedules contingency reserve of 2,000 MW, all of which must be fully deployed in 10 minutes [22]. This represents about 3.3% of MISO's 2009 average load of 61,000 MW and about 2.1% of 2009 peak load of 96,500 MW. In our system, we scheduled 3.5% of load as spinning reserve in each interval, rather than the annual average.

Ramp Response Time and *Ramp Intervals*: MISO's proposal targets ramp capability to cover variability and uncertainty over 10 minutes, or two real-time intervals in their system [5]. Our system uses 10-minute intervals, so we targeted ramp capability to cover a single real-time interval.

Over-generation Penalty, Under-generation penalty, Spinning Reserve Scarcity Price: These three values are penalty prices to ensure that supply and demand remain in balance and that sufficient spinning reserves are procured if possible. We set the over-generation penalty to $500/MWh which is based on MISO's offer floor of -$500/MWh. This was very high in part to prioritize wind curtailment before an over-generation event. We set the under-generation penalty to MISO's value of lost load of $3500/MWh and the spinning reserve scarcity price to MISO's Operating Reserve Demand Curve Scarcity Price of $1100/MWh [3]. These relative values are such that in intervals with insufficient generation, the models prioritized meeting energy demand before meeting reserves, which is desirable.

URC Demand Curve Price and *DRC Demand Curve Price*: These were based on MISO's ramp capability products proposal and were both set at $10 [5]. These prices ensured that ramp capability was procured if it was inexpensive, but wouldn't be prioritized over energy or spinning reserves.

		Model Version			
Variable Name	**Description**	**B-DAUC/ B-DAED**	**B-RTED**	**RC-DAUC/ RC-DAED**	**RC-RTED**
T	# Intervals in Time Horizon [intervals]	24	1	24	1
IntLength	Length of each interval [minutes]	60	10	60	10
SpinPercentage	% of load required for spinning reserve	3.5	3.5	3.5	3.5
ResResponseTime	time by which spinning reserve must be deployable [minutes]	10	10	10	10
RampResponseTime	Response time for ramp capability [minutes]	--	--	10	--
RampInts	# intervals for which ramp capability is considered [intervals]	--	--	--	1
OverGenPen	Over generation penalty [$/MWh]	500	500	500	500
UnderGenPen	Under generation penalty [$/MWh]	3,500	3,500	3,500	3,500
SRScarcityPen	System-wide spinning reserve shortage penalty [$/MWh]	1,100	1,100	1,100	1,100
RCUpDCPrice	URC Demand Curve Price [$/MWh]	10	10	10	10
RCDownDCPrice	DRC Demand Curve Price [$/MWh]	10	10	10	10

Table 8 - System-wide parameters for each of the four combinations of time horizon (day-ahead and real-time) and model formulation (baseline and ramp capability)

2.5 Targeted quantity of ramp capability

The targeted quantity of ramp capability to procure is designed to vary based on both forecasted change in net load as well as on uncertainty surrounding that forecast. Uncertainty is calculated through historical statistical analysis of variability in similar intervals. Therefore, an auxiliary process must be run to determine values for *RCUpDCMax* and *RCDownDCMax* in each interval. The basic equations for ramp capability are as follows. Note that in these formulations, DRC and downward uncertainty are both non-negative.

Real-time

$$RCUpDCMax_t = Max[(ForecastNetLoad_{t+1} - ActualNetLoad_t) + UncertaintyUp_{t+1}, 0] \quad (69)$$

$$RCDownDCMax_t = \\ Max[(ActualNetLoad_t - ForecastNetLoad_{t+1}) + UncertaintyDown_{t+1}, 0] \tag{70}$$

Day-ahead

$$RCUpDCMax_t = \\ Max\left[(ForecastNetLoad_{t+1} - ForecastNetLoad_t) * \frac{RampResponseTime}{IntLength} + \\ UncertaintyUp_t, 0\right] \tag{71}$$

$$RCDownDCMax_t = \\ Max\left[(ForecastNetLoad_t - ForecastNetLoad_{t+1}) * \frac{RampResponseTime}{IntLength} + \\ UncertaintyDown_t, 0\right] \tag{72}$$

The difference in the real-time and day-ahead formulations is due to their differing granularity. The real-time model simply attempts to procure enough ramp capability to ensure that it can meet the forecast and uncertainty for the following interval (see Figure 3). The day-ahead model, on the other hand, tries to manage the intra-interval variability and uncertainty that will occur when the generating units committed in the day-ahead market are used to supply actual load in the more volatile real-time market with higher time resolution (see Figure 4).

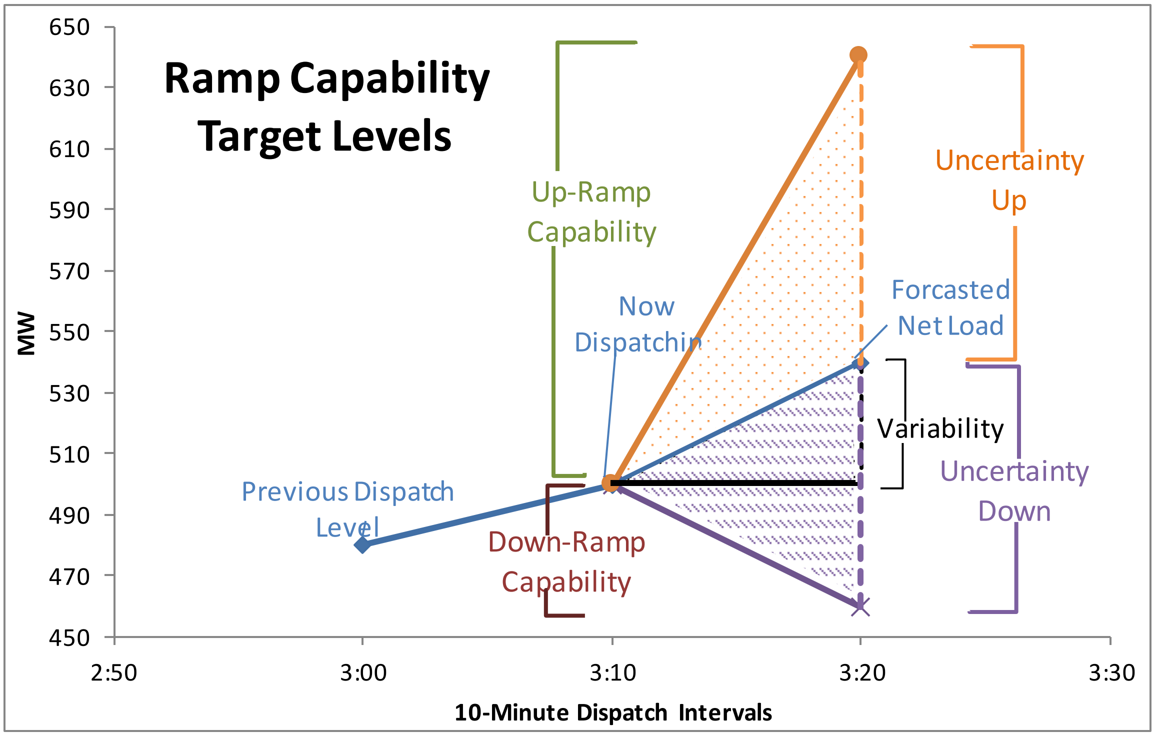

Figure 3 - Ramp capability target levels in real-time economic dispatch. The model targets URC and DRC to not only meet the forecast in the following interval, but the uncertainty surrounding that forecast as well.

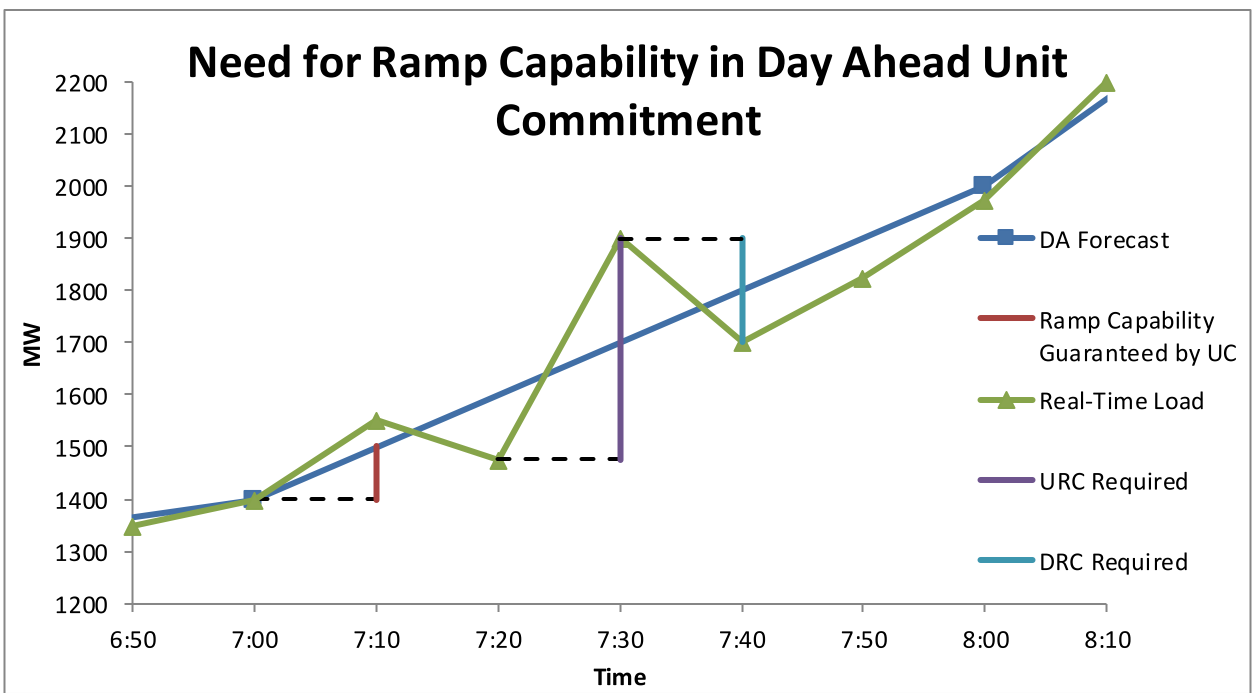

Figure 4 - Need for ramp capability in the day ahead model. The DAUC model run will procure sufficient ramp capability to move from the forecasted average net load in the 7:00 interval to the forecasted average net load in the 8:00 interval. This ensures that 1/6 of that ramp capability will be available in any 10-minute interval. However, even if the forecast is very accurate, the real-time ramping needs may be larger in either direction in any 10-minute interval.

The same uncertainty values were used by the day-ahead and real-time models. In order to calculate these, we took the following steps for both the low and high wind scenarios:

1. We subtracted real-time wind generation from real-time load to calculate net load for 2009, the year preceding the modeled year.
2. We classified each interval by season, time of day, and whether it fell on a weekend or weekday, as each of these categories has a significant impact on direction and quantity of ramping need. We used three seasons, winter, spring/fall, and summer (Table 9). Spring and fall were combined, as they have very similar net load profiles. We used four time-of-day periods: morning, midday, evening, and night (Table 10). Thus we had 24 different classifications for each wind scenario.
3. For each interval, we found the ramp percentage (percent change in net load from previous interval). We then calculated the mean and standard deviation of ramp percentage for each of the 24 groups. Figure 5 shows a sample PDF for ramp percentages in group 5: winter weekday mornings under the high wind scenario.
4. For each group, we calculated uncertainty % as follows:

$$UncertaintyUpPercent = MeanRampPercent + 2 * SDRampPercent \tag{73}$$

$$UncertaintyDownPercent = -1 * (MeanRampPercent - 2 * SDRampPercent) \tag{74}$$

   Table 11 and Table 12 show the calculated uncertainty percentages for each group.
5. In each interval, net load was multiplied by the two uncertainty percentages for the appropriate group to find *UncertaintyUp* and *UncertaintyDown* for each interval.

Month	Season
January	Winter
February	Winter
March	Spring/Fall
April	Spring/Fall
May	Spring/Fall
June	Summer
July	Summer
August	Summer
September	Summer
October	Spring/Fall
November	Spring/Fall
December	Winter

Table 9 - Seasonal classification of months based on similar net load profiles, used for uncertainty calculations.

Time Period	Hours
Morning	04 - 09
Midday	10 - 16
Evening	17 - 20
Night	21 - 03

Table 10 - Classification of hourly intervals into time periods based on ramping characteristics, used for uncertainty calculations.

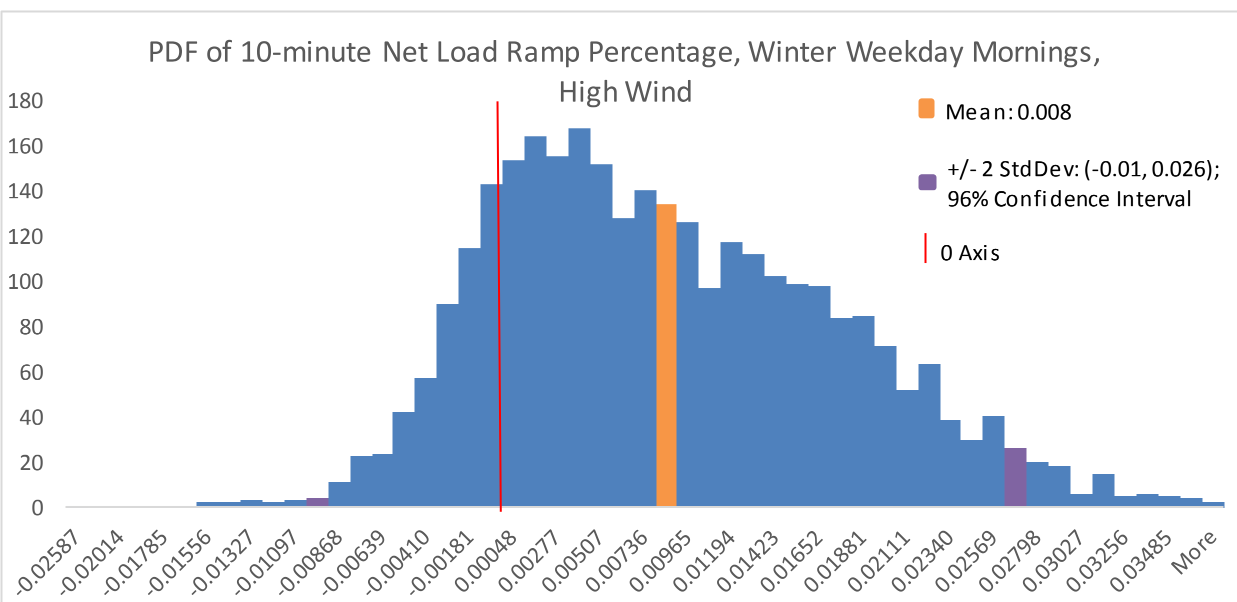

Figure 5 - PDF of 10-minute net load ramp percentage in Group 5: winter weekday mornings under the high wind scenario. We see much more need for URC than DRC in this group. Bins containing the mean as well as plus/minus two standard deviations from the mean are highlighted. In this distribution, two standard deviations from the mean represents a 96% confidence interval.

Uncertainty in Low Wind Scenario					
Season	**Weekday**	**Time of Day**	**Group Number**	**Uncertainty Up (% of Net Load)**	**Uncertainty Down (% of Net Load)**
Winter	Weekend	Morning	1	1.34%	-0.46%
		Midday	2	0.72%	-0.75%
		Evening	3	1.92%	-1.28%
		Night	4	0.30%	-1.52%
	Weekday	Morning	5	2.26%	-0.79%
		Midday	6	0.54%	-0.74%
		Evening	7	1.55%	-1.17%
		Night	8	0.39%	-1.63%
Spring/Fall	Weekend	Morning	9	1.75%	-0.50%
		Midday	10	0.82%	-0.98%
		Evening	11	1.77%	-1.24%
		Night	12	0.55%	-1.82%
	Weekday	Morning	13	2.68%	-0.87%
		Midday	14	0.60%	-0.93%
		Evening	15	1.39%	-1.26%
		Night	16	0.81%	-2.09%
Summer	Weekend	Morning	17	2.28%	-0.81%
		Midday	18	1.21%	-0.72%
		Evening	19	1.04%	-1.34%
		Night	20	0.69%	-2.35%
	Weekday	Morning	21	2.46%	-0.34%
		Midday	22	0.96%	-0.74%
		Evening	23	0.82%	-1.39%
		Night	24	0.72%	-2.43%

Table 11 - Uncertainty in each direction as a percentage of net load for each of 24 groups in the low wind scenario

Uncertainty in Low Wind Scenario					
Season	Weekday	Time of Day	Group Number	Uncertainty Up (% of Net Load)	Uncertainty Down (% of Net Load)
Winter	Weekend	Morning	1	1.62%	-0.70%
		Midday	2	1.00%	-1.04%
		Evening	3	2.12%	-1.52%
		Night	4	0.60%	-1.88%
	Weekday	Morning	5	2.60%	-1.00%
		Midday	6	0.79%	-0.97%
		Evening	7	1.71%	-1.43%
		Night	8	0.63%	-1.94%
Spring/Fall	Weekend	Morning	9	2.33%	-0.86%
		Midday	10	1.31%	-1.58%
		Evening	11	2.24%	-1.69%
		Night	12	1.06%	-2.42%
	Weekday	Morning	13	3.14%	-1.11%
		Midday	14	0.99%	-1.41%
		Evening	15	1.78%	-1.67%
		Night	16	1.23%	-2.62%
Summer	Weekend	Morning	17	2.87%	-1.14%
		Midday	18	1.71%	-1.24%
		Evening	19	1.44%	-1.86%
		Night	20	1.39%	-3.17%
	Weekday	Morning	21	3.05%	-0.67%
		Midday	22	1.31%	-1.13%
		Evening	23	1.18%	-1.85%
		Night	24	1.23%	-3.08%

Table 12 - Uncertainty in each direction as a percentage of net load for each of 24 groups in the high wind scenario

3. Results and Discussion

3.1 Procurement of Ramp Capability

As demonstrated in Figure 2, URC and DRC was not expected to be procured in every interval, due to either the existence of the demand curve or to the lack of a need for additional ramp capability beyond what is already available in the system. Table 13 and Table 14 show the percentage of intervals that fell into each category of procurement shown in Figure 2, as well as the average quantity procured in intervals where a redispatch occurred.

Some quantity of up-ramp capability was procured in 13-20% of intervals depending on the month and wind scenario. These were the only intervals in which the existence of the URC product had any impact on commitment or dispatch. In the day-ahead market, we note that the $10/MWh price cap was a limiting factor far less frequently than in the real-time market, and in fact there were no day-ahead intervals in which all targeted URC was too expensive, whereas this occurred in 10-17% of intervals in the real-time market. This was due to the ability of the day-ahead market to commit additional resources to meet the up-ramp capability target, while the real-time market could only use resources previously committed. In those intervals in which a redispatch did occur, approximately 26-32 MW of URC was procured in the day-ahead market and 62-83 MW in the real-time market.

Results for the down-ramp capability product are somewhat more surprising, as no additional DRC was procured in any interval in any scenario. Essentially, this product had no impact on either the commitment or the dispatch, indicating that the system under the baseline model was sufficiently flexible to meet all down-ramping needs. It is worth noting a related outcome here: there was no wind curtailment in the baseline model. It is expected that these results would go hand-in-hand; wind curtailment in the baseline model would be reduced by down-ramp capability procured in the ramp capability model. However, there is wind curtailment within the real-world MISO system [23], and therefore there is a need for DRC. This indicates that our scaled-down system is more flexible, at least in the down-ramp direction, than MISO's system as a whole. Possible reasons why our model power system fails to represent the lack of flexibility of MISO (and the associated occurrence of wind curtailment episodes) include the following:

1. *Transmission constraints*: Much of MISO's wind curtailment occurs in transmission constrained areas where wind capacity makes up a much higher percentage of the generation capacity than the system as a whole [23], and therefore more flexibility is required. As a simplification, we did not include transmission constraints in our model, so curtailment due to congestion did not occur.
2. *Ramp rate assumptions*: Generator operating parameters are not typically public knowledge. Therefore we relied on academic and government research papers to assist with the needed assumptions. It is possible that our coal plant ramp rates, particularly plant 4 (see Table 4) may have been too high. Because coal plants have lower marginal costs than natural gas plants, they are generally dispatched at their highest levels. This combined with the overestimated ramp rates led to increased down-ramp capability.

3. *Minimum generation levels*: As noted in 2.4.2, we reduced our original assumptions for minimum generation levels for several plants in order to ensure that plants could startup or shutdown without violating either the minimum generation or maximum ramp rate constraints. This was necessary because our model does not use different ramp rates during startup and shutdown intervals. However, this simplification increased the amount of downward flexibility for any generator operating above its minimum level.
4. *Wind volatility*: It is possible that the simulated wind data that we used is less volatile or that the simulated forecasts were more accurate than typical wind farms in the MISO region, either of which would lead to a decreased need for wind curtailment.

		URC Procurement					
		No URC Procured			URC Procured		
		No URC Targeted	System Sufficiently Flexible; Target Met	URC too Expensive; Demand Curve Price Exceeded	Procured All Targeted URC	Procured Some Targeted URC; Demand Curve limits full quantity	Average quantity procured when change in dispatch occurs (MW)
January Low Wind	Day-Ahead	23%	62%	0%	1%	14%	30
	Real-Time	21%	54%	10%	2%	12%	62
January High Wind	Day-Ahead	19%	66%	0%	1%	15%	31
	Real-Time	18%	56%	14%	2%	11%	73
April Low Wind	Day-Ahead	22%	64%	0%	1%	13%	26
	Real-Time	18%	60%	9%	2%	10%	62
April High Wind	Day-Ahead	15%	65%	0%	4%	16%	31
	Real-Time	14%	54%	17%	5%	11%	71
July Low Wind	Day-Ahead	27%	56%	0%	0%	17%	31
	Real-Time	21%	54%	10%	1%	15%	72
July High Wind	Day-Ahead	19%	61%	0%	0%	20%	32
	Real-Time	13%	55%	13%	1%	18%	83
Overall Low Wind	Day-Ahead	24%	61%	0%	1%	15%	29
	Real-Time	20%	56%	10%	2%	12%	65
Overall High Wind	Day-Ahead	18%	64%	0%	1%	17%	31
	Real-Time	15%	55%	14%	3%	13%	76

Table 13 - Up-Ramp Capability Procurement Categories. For each month and wind combination, this table shows the frequency of each category of procurement. Note that the two categories in which URC are procured are the only intervals when the dispatch changes.

		DRC Procurement				
		No DRC Procured			DRC Procured	
		No DRC Targeted	System Sufficiently Flexible; Target Met	Procurement too Expensive; Demand Curve Price Exceeded	Procured All Targeted DRC	Procured Some Targeted DRC; Demand Curve limits full procurement
January Low Wind	Day-Ahead	20%	80%	0%	0%	0%
	Real-Time	13%	87%	0%	0%	0%
January High Wind	Day-Ahead	16%	84%	0%	0%	0%
	Real-Time	13%	87%	0%	0%	0%
April Low Wind	Day-Ahead	16%	84%	0%	0%	0%
	Real-Time	14%	86%	0%	0%	0%
April High Wind	Day-Ahead	14%	86%	0%	0%	0%
	Real-Time	13%	87%	0%	0%	0%
July Low Wind	Day-Ahead	30%	70%	0%	0%	0%
	Real-Time	25%	75%	0%	0%	0%
July High Wind	Day-Ahead	24%	76%	0%	0%	0%
	Real-Time	19%	81%	0%	0%	0%
Overall Low Wind	Day-Ahead	22%	78%	0%	0%	0%
	Real-Time	17%	83%	0%	0%	0%
Overall High Wind	Day-Ahead	18%	82%	0%	0%	0%
	Real-Time	15%	85%	0%	0%	0%

Table 14 - Down-Ramp Capability Procurement Categories. For each month and wind combination, this table shows the frequency of each category of procurement. Note that DRC is never procured, so the addition of the DRC product does not alter the dispatch.

3.2 Reliability

We find that the URC product significantly improved system reliability, particularly as wind penetration increased. In our simulation, system reliability problems were represented by energy and spinning reserve shortages in the results of the real-time economic dispatch model. An energy shortage occurs when there is insufficient generation committed to meet demand and is a severe problem, whereas a spinning reserve shortage leaves the system vulnerable to outages. In the baseline model, between 1 - 6% of intervals contained energy shortages depending on the month and wind scenario (Figure 6), while 16 - 25% of intervals contained spinning reserve shortages (Figure 7). In each month, there were more shortages under the high-wind scenario. The URC product universally reduced both types of shortages in all month/wind scenario combinations; on average, energy shortages were cut in half and reserve shortages reduced by 24%.

It is important to note that these occurrences were much higher in our model than they are in reality. In 2010, for example, MISO experienced spinning reserve shortages in just over 1% of all real-time intervals [24] and likely did not have any actual energy shortages. This is because MISO has a number of ways to deal with potential shortage events that are outside of the scope of our model, such as an additional short-term unit commitment run, the ability to curtail load via demand response programs, and the manual dispatch (bypassing the outcome of the optimization models) of very expensive fast ramping generators. Nevertheless, these intervals represent intervals in which there is a potential reliability problem, and their reduction is beneficial.

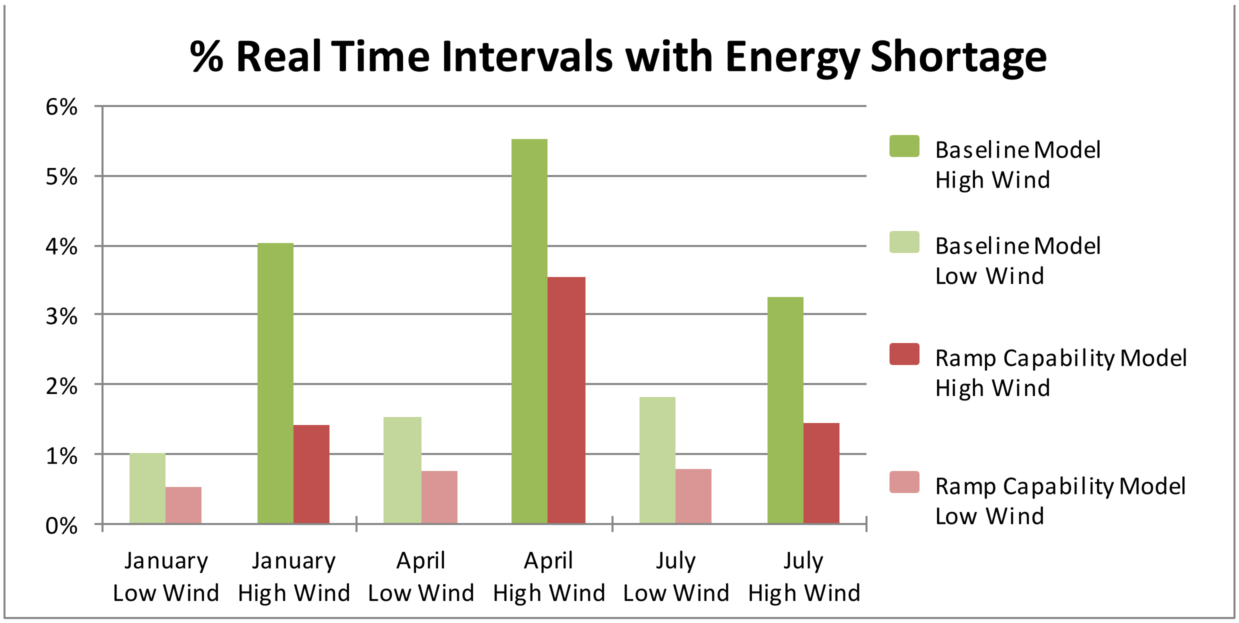

Figure 6 - Percent of intervals in real-time economic dispatch that contain an energy shortage. Note that there are more shortages in high-wind scenarios in the baseline model and that the ramp capability model reduces shortages in all month/wind combinations.

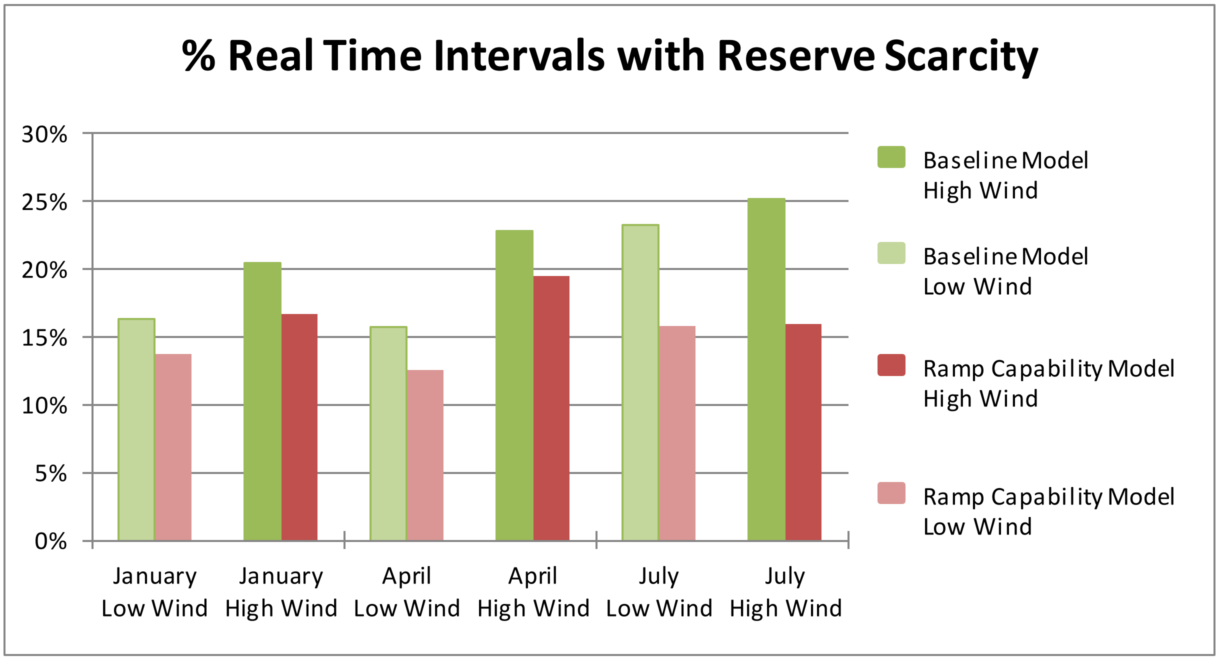

Figure 7 - Percent of intervals in real-time economic dispatch with spinning reserve scarcity. Note that there are more shortages in the high-wind scenario and that the ramp capability model reduces shortages in all month/wind combinations.

3.3 Prices

The expected impacts of the URC product in the real-time market are slightly higher energy prices during typical intervals which are more than offset by a reduction in price spikes, leading to lower average prices overall. The results of the simulation demonstrated this tradeoff. Figure 8 shows that average market clearing energy prices in the baseline model ranged from \$230-\$407/MWh. The URC product reduced prices by 17% to 37%, a savings of \$40-\$140/MWh. Average real-time prices were much higher in the simulation than the \$30-\$60/MWh found in MISO's market in 2010 [24]. This was due to the elevated frequencies of energy and spinning reserve shortages in the simulation described in section 3.2, which were associated with penalty prices of \$3,500/MWh and \$1,100/MWh respectively. Figure 9 shows that the average prices in non-shortage conditions were much closer to MISO's actual average prices. Here we see the expected slight increase of \$1 - \$2 needed to procure URC.

As discussed in section 3.1, the ramp capability product did not procure any DRC. While this clearly means that the DRC product produced no benefit to the system, it also did not incur any costs because the ramp capability products are priced solely based on the opportunity costs of procurement. This illustrates the low-risk nature of implementing the URC and DRC products when compared to other ancillary services. In intervals when they are not necessary to ensure system flexibility, they will cost nothing.

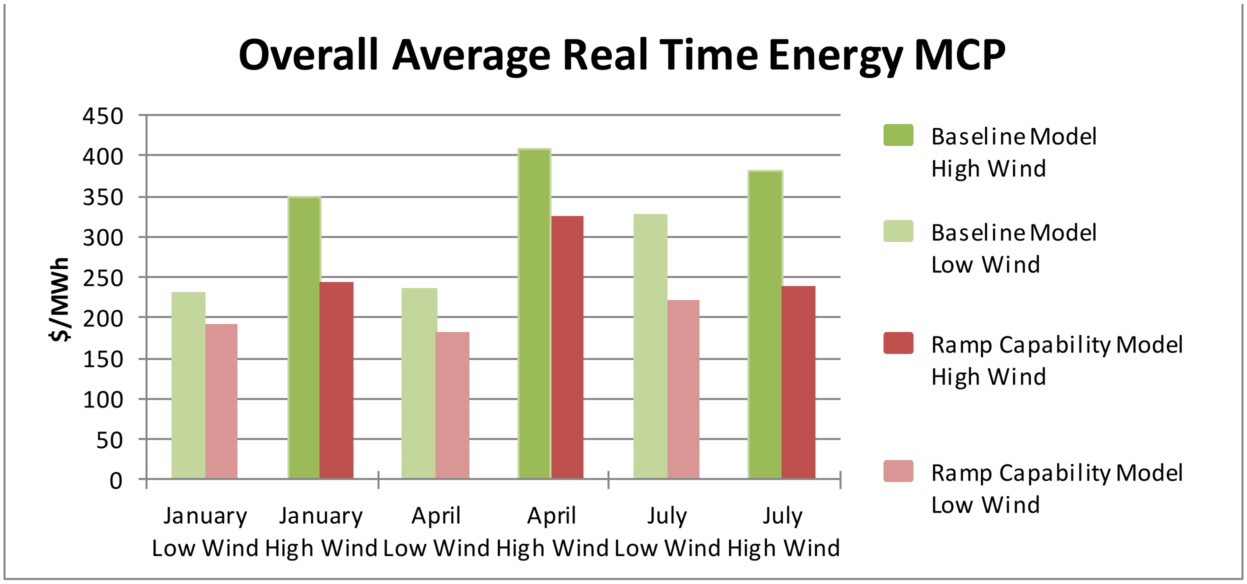

Figure 8 - Average real-time energy market clearing price. Note the prices are very high compared to generators' marginal costs due to high penalty prices associated with energy and reserve shortage intervals and that the ramp capability model decreases prices in all month/wind combinations.

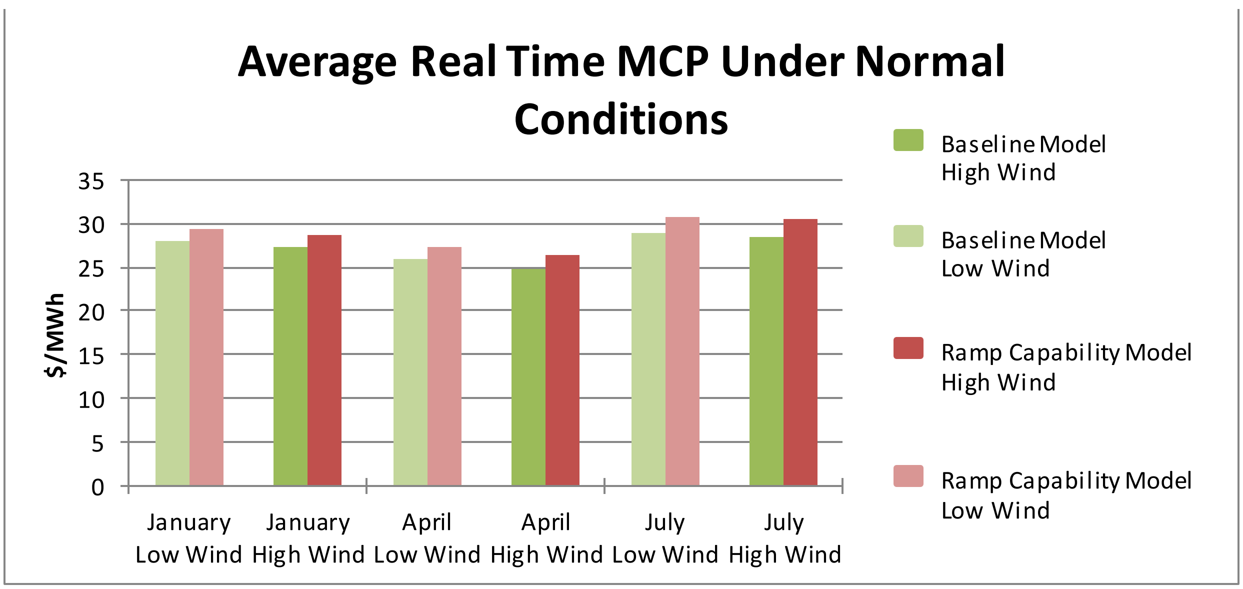

Figure 9 - Average real-time energy market clearing price in non-shortage intervals.

3.4 Generation Fuel Mix and CO_2 emissions

We would expect the implementation of the ramp capability product to result in some amount of fuel switching from less flexible coal generators to more flexible natural gas generators as well as a corresponding reduction in CO_2 emissions, as natural gas plants have a lower carbon intensity. Figure 10 shows this expectation held true, with a reduction of 0% to 1.2% of coal generation and 0% to 0.5% of CO_2 emissions with the ramp capability model in place. These figures may seem somewhat small, but given that the ramp capability product caused a change in dispatch in only 13-20% of intervals, and the URC procured was on the order of 1%-3% of total load, the amount of fuel switching is reasonable.

As discussed in section 3.1, our baseline model did not prescribe any wind curtailment, nor did the ramp capability model procure any DRC, both of which are results that do not likely reflect real-world conditions. Had wind been curtailed in the baseline model, we would have seen higher CO_2 emissions in the baseline model as wind generation was replaced by fossil fuel generation. To the extent that the DRC product would have reduced the amount of wind curtailment, we would have seen increased CO_2 emissions savings under the ramp capability model.

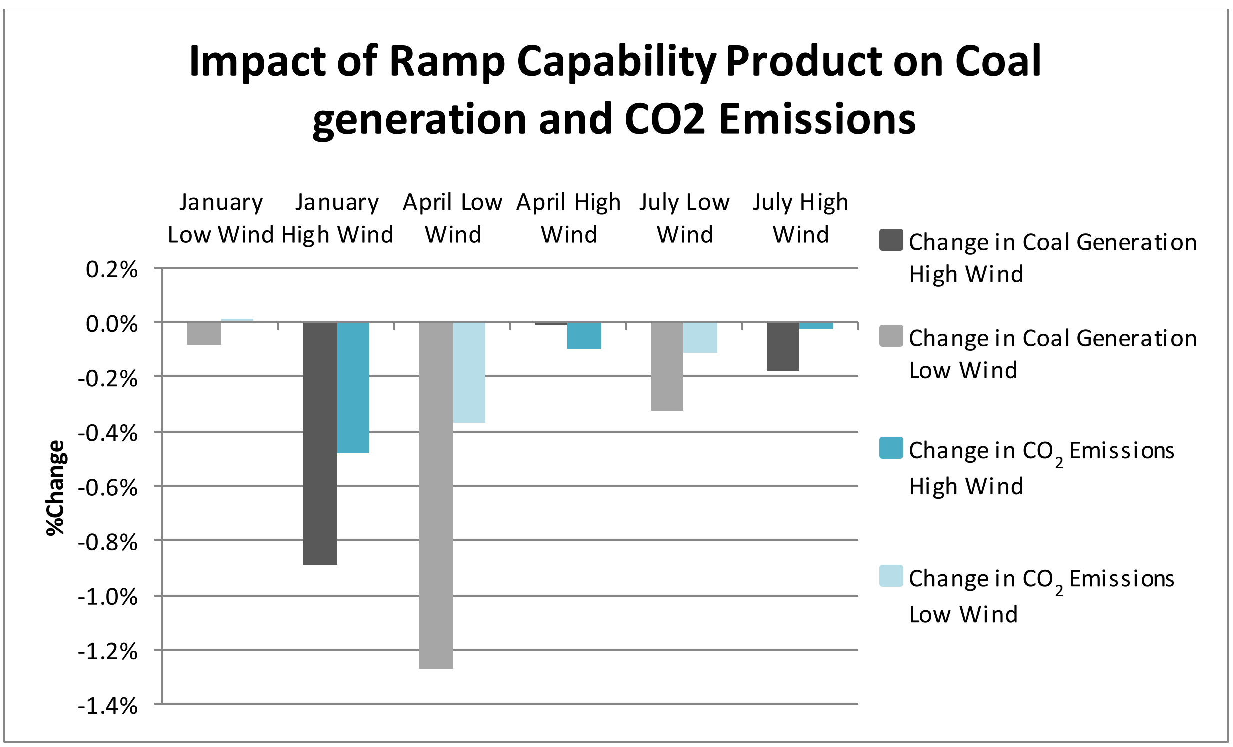

Figure 10 – Percent reduction in coal generation and CO_2 emissions with the ramp capability products relative to the baseline model

4. Conclusion

Within our scaled-down representation of MISO's power system, we find that the implementation of the proposed up-ramp capability product provides significant reliability benefits by altering the commitment and dispatch so that more flexible resources are available to quickly ramp up generation when needed. This results in fewer intervals in the real-time market in which there is a shortage of either energy or spinning reserve. While there is a small price increase in non-shortage intervals due to the procurement of URC, this is far outweighed by the avoidance of huge penalty prices associated with shortage intervals. A secondary effect of the URC product is a small amount of fuel switching from coal to the more flexible natural gas, which slightly reduces the system's overall CO_2 emissions. However, the more pronounced environmental benefit is the ability of the URC product to help the system absorb increased wind penetration while avoiding most of the corresponding increase in reliability problems. Although the DRC product had no impact within our simulation, we believe that it would be beneficial in any system, such as MISO, in which wind is curtailed.

Future work should include running the simulation on a more realistic test system that includes transmission constraints and more realistic ramp rate assumptions. In addition, a short-term unit commitment model should be added in order to more closely mirror MISO practices and better manage the transition between the day-ahead market with hourly intervals and the real-time market with 10-minute intervals. Such a model would likely reduce the frequency of shortage events and allow a more accurate assessment of the price-related benefits of the ramp capability products. Finally, it would be useful to conduct a parametric analysis of shortage penalty prices, ramp-capability demand curve, target levels of spinning reserve and ramp capability, and forecast errors for wind and load to determine ways in which these parameters should be chosen in relation to the size and characteristics of the system represented. The values for these parameters used in our analysis correspond to the values in MISO's system and may not be appropriate for a scaled down and simplified system as in our simulation.

Works Cited

1. Midcontinent Independent System Operator. *MISO Value Proposition Benefits*. 2013 [cited 2014 April 20]; Available from: https://www.misoenergy.org/Library/Repository/Communication%20Material/One-Pagers/Value_Prop_2013_OnePager.pdf.
2. Kirschen, D. and G. Strbac, *Fundamentals of Power System Economics*. 2004, West Sussex, England: John Wiley & Sons, Ltd.
3. Midwest Independent System Operator, *Business Practices Manual: Energy and Operating Reserve Markets*. 2013.
4. California Independent System Operator, *Settlements and Billing: BPM Configuratin Guide: Exceptional Dispatch Uplift Settlement.* 2012.
5. Navid, N. and G. Rosenwald *Ramp Capability Product Design for MISO Markets*. 2013.
6. Xu, L. and D. Tretheway *Flexible Ramping Products: Second Revised Draft Final Proposal*. 2012.
7. Navid, N. and G. Rosenwald, *Market solutions for managing ramp flexibility with high penetration of renewable resource.* Sustainable Energy, IEEE Transactions on, 2012. **3**(4): p. 784-790.
8. Wang, B. and B.F. Hobbs, *A flexible ramping product: Can it help real-time dispatch markets approach the stochastic dispatch ideal?* Electric Power Systems Research, 2014. **109**: p. 128-140.
9. Potomac Economics, *2012 State ofhte Market Report for the MISO Electricity Markets*. 2013.
10. Carrión, M. and J.M. Arroyo, *A computationally efficient mixed-integer linear formulation for the thermal unit commitment problem.* Power Systems, IEEE Transactions on, 2006. **21**(3): p. 1371-1378.
11. US Environmental Protection Agency, *Emissions & Generation Resource Integrated Database, 2009 Data Files*. 2012.
12. Federal Energy Regulatory Commission, *RTO Unit Commitment Winter Test System.* 2012.
13. *PJM*. 2014; Available from: www.pjm.com.
14. MacMillan, S., A. Antonyuk, and H. Schwind, *Gas to Coal Competition in the U.S. Power Sector*, International Energy Agency, Editor. 2013.
15. Energy Information Administration. *Average Heat Content by State and Region, Electric Power Sector*. Coal Data Browser 2014; Available from: http://www.eia.gov/beta/coal/data/browser/.
16. Energy Information Administration. *Average Sales Price By State and Disposition*. 2013; Available from: http://www.eia.gov/coal/annual/xls/table33.xls.
17. Energy Information Administration. *U.S. Natural Gas Electric Power Price, Annual Data*. 2014; Available from: http://www.eia.gov/dnav/ng/hist/n3045us3A.htm.
18. National Renewable Energy Laboratory. *Eastern Wind Dataset*. 2012; Available from: http://www.nrel.gov/electricity/transmission/eastern_wind_methodology.html.
19. Rybarik, B. *NARUC Annual Meeting 2013, Staff subcommittee on Electric Reliability*. 2013; Available from: http://www.narucmeetings.org/Presentations/MISO1.pdf.
20. American Wind Energy Association. *Wind Energy Facts at a Glance*. 2014; Available from: http://awea.rd.net/Resources/Content.aspx?ItemNumber=5059.
21. LCG Consulting. *MISO Actual Load*. 2014; Available from: http://energyonline.com/Data/GenericData.aspx?DataId=10&MISO___Actual_Load.
22. Midwest Independent System Operator. *Business Rules Governing Contingency Reserve Provided by Batch-Load Demand Response*. 2013; Available from: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=146463.

23. Ruud, K. *Curtailment of Wind Farms Output*. 2013; Available from: http://renewableenergy.illinoisstate.edu/downloads/speaker_presentations/071712_iwwg_annual_conference/071812_AM_1045_Kris_Ruud.pdf.
24. Potomac Economics, *State of the Market Report for the MISO Electricity Markets, 2010*. 2011.